

HOUSE BILL NO. 558

AMENDMENT IN THE NATURE OF A SUBSTITUTE

(Proposed by the House Committee on Commerce and Energy

on _____)

(Patron Prior to Substitute--Delegate O'Quinn)

A BILL to amend and reenact §§ 56-248.1, 56-265.1, and 56-600 through 56-604 of the Code of Virginia and to amend the Code of Virginia by adding in Title 56 a chapter numbered 30, consisting of a section numbered 56-625, relating to natural gas, biogas, and other gas sources of energy; definitions; energy conservation and efficiency; Steps to Advance Virginia's Energy Plan; biogas supply infrastructure projects.

Be it enacted by the General Assembly of Virginia:

1. That §§ 56-248.1, 56-265.1, and 56-600 through 56-604 of the Code of Virginia are amended and reenacted and that the Code of Virginia is amended by adding in Title 56 a chapter numbered 30, consisting of a section numbered 56-625, as follows:

§ 56-248.1. Commission to monitor fuel prices and utility fuel purchases; fuel price index.

A. The Commission shall monitor all fuel purchases, transportation costs, and contracts for such purchases of a utility to ascertain that all feasible economies are being utilized. Subject to the provisions of § 56-234, the Commission shall allow natural gas utilities to include in their fuel portfolios supplemental or substitute forms of gas sources that meet the natural gas utility's pipeline quality gas standards and that reduce the emissions intensity of its fuel portfolio. A natural gas utility shall procure supplemental or substitute forms of gas sources utilizing standard industry practices and shall report to the Commission annually the imputed reduction in carbon dioxide equivalent resulting from such purchasing practices.

B. As used in this section:

25 "Biogas" means a mixture of hydrocarbons that is a gas at 60 degrees Fahrenheit and one
26 atmosphere of pressure that is produced through the anaerobic digestion or thermal conversion of organic
27 matter.

28 "Low-emission natural gas" means natural gas produced from a geologic source that has a methane
29 intensity of 0.20 or less (i) as reported under a protocol approved by the federal Environmental Protection
30 Agency's Gas STAR Methane Challenge, (ii) as certified by the United Nations Environment Programme's
31 Oil and Gas Methane Partnership 2.0, or (iii) as validated under a Qualified Attribute Commodities
32 Platform.

33 "Methane intensity" means the methane emissions assigned to natural gas on an energy basis
34 divided by the total methane content of produced natural gas.

35 "Qualified Attribute Commodities Platform" means a trading mechanism for natural gas or natural
36 gas attributes that are nonfinancial intangible commodities that represents, packages, and certifies the
37 qualifying attributes of an amount of low-emission natural gas. A Qualified Attribute Commodities
38 Platform provides validation by an independent third party, provides natural gas or natural gas attributes
39 capable of bilateral or exchange contract trading pursuant to standardized contracts for physical delivery
40 that reasonably eliminate validation risk, and provides transparency for audit and reporting purposes.

41 "Supplemental or substitute forms of gas sources" means (i) low-emission natural gas, (ii) biogas,
42 or (iii) hydrogen.

43 C. In addition, the Commission shall establish a fuel price index in order to compare the prices
44 paid for the various types of fuel by Virginia utilities with the average price of the various types of fuel
45 paid by other public utilities at comparable geographic locations in the market.

46 D. This section shall not apply to telephone companies.

47 **§ 56-265.1. Definitions.**

48 In this chapter, the following terms shall have the following meanings:

49 (a) "Company" means a corporation, a limited liability company, an individual, a partnership, an
50 association, a joint-stock company, a business trust, a cooperative, or an organized group of persons,
51 whether incorporated or not; or any receiver, trustee or other liquidating agent of any of the foregoing in

52 his capacity as such; but not a municipal corporation or a county, unless such municipal corporation or
53 county has obtained a certificate pursuant to § 56-265.4:4.

54 (b) "Public utility" means any company that owns or operates facilities within the Commonwealth
55 of Virginia for the generation, transmission, or distribution of electric energy for sale, for the production,
56 storage, transmission, or distribution, otherwise than in enclosed portable containers, of natural-~~or~~
57 manufactured gas, or, if produced, stored, transmitted, or distributed by a natural gas utility as defined in
58 § 56-265.4:6, supplemental or substitute forms of gas sources as defined in § 56-248.1, or geothermal
59 resources for sale for heat, light or power, or for the furnishing of telephone service, sewerage facilities or
60 water. A "public utility" may own a facility for the storage of electric energy for sale that includes one or
61 more pumped hydroelectricity generation and storage facilities located in the coalfield region of Virginia
62 as described in § 15.2-6002. However, the term "public utility" does not include any of the following:

63 (1) Except as otherwise provided in § 56-265.3:1, any company furnishing sewerage facilities,
64 geothermal resources or water to less than 50 customers. Any company furnishing water or sewer services
65 to 10 or more customers and excluded by this subdivision from the definition of "public utility" for
66 purposes of this chapter nevertheless shall not abandon the water or sewer services unless and until
67 approval is granted by the Commission or all the customers receiving such services agree to accept
68 ownership of the company.

69 (2) Any company generating and distributing electric energy exclusively for its own consumption.

70 (3) Any company (A) which furnishes electric service together with heating and cooling services,
71 generated at a central plant installed on the premises to be served, to the tenants of a building or buildings
72 located on a single tract of land undivided by any publicly maintained highway, street or road at the time
73 of installation of the central plant, and (B) which does not charge separately or by meter for electric energy
74 used by any tenant except as part of a rental charge. Any company excluded by this subdivision from the
75 definition of "public utility" for the purposes of this chapter nevertheless shall, within 30 days following
76 the issuance of a building permit, notify the State Corporation Commission in writing of the ownership,
77 capacity and location of such central plant, and it shall be subject, with regard to the quality of electric
78 service furnished, to the provisions of Chapters 10 (§ 56-232 et seq.) and 17 (§ 56-509 et seq.) and

79 regulations thereunder and be deemed a public utility for such purposes, if such company furnishes such
80 service to 100 or more lessees.

81 (4) Any company, or affiliate thereof, making a first or direct sale, or ancillary transmission or
82 delivery service, of natural ~~or manufactured~~ gas to fewer than 35 commercial or industrial customers,
83 which are not themselves "public utilities" as defined in this chapter, or to certain public schools as
84 indicated in this subdivision, for use solely by such purchasing customers at facilities which are not located
85 in a territory for which a certificate to provide gas service has been issued by the Commission under this
86 chapter and which, at the time of the Commission's receipt of the notice provided under § 56-265.4:5, are
87 not located within any area, territory, or jurisdiction served by a municipal corporation that provided gas
88 distribution service as of January 1, 1992, provided that such company shall comply with the provisions
89 of § 56-265.4:5. Direct sales or ancillary transmission or delivery services of natural gas to public schools
90 in the following localities may be made without regard to the number of schools involved and shall not
91 count against the "fewer than 35" requirement in this subdivision: the Counties of Dickenson, Wise,
92 Russell, and Buchanan, and the City of Norton.

93 (5) Any company which is not a public service corporation and which provides compressed natural
94 gas service at retail for the public.

95 (6) Any company selling landfill gas from a solid waste management facility permitted by the
96 Department of Environmental Quality to a public utility certificated by the Commission to provide gas
97 distribution service to the public in the area in which the solid waste management facility is located. If
98 such company submits to the public utility a written offer for sale of such gas and the public utility does
99 not agree within 60 days to purchase such gas on mutually satisfactory terms, then the company may sell
100 such gas to (i) any facility owned and operated by the Commonwealth which is located within three miles
101 of the solid waste management facility or (ii) any purchaser after such landfill gas has been liquefied. The
102 provisions of this subdivision shall not apply to the City of Lynchburg or Fairfax County.

103 (7) Any authority created pursuant to the Virginia Water and Waste Authorities Act (§ 15.2-5100
104 et seq.) making a sale or ancillary transmission or delivery service of landfill gas to a commercial or
105 industrial customer from a solid waste management facility permitted by the Department of Environmental

106 Quality and operated by that same authority, if such an authority limits off-premises sale, transmission or
107 delivery service of landfill gas to no more than one purchaser. The authority may contract with other
108 persons for the construction and operation of facilities necessary or convenient to the sale, transmission
109 or delivery of landfill gas, and no such person shall be deemed a public utility solely by reason of its
110 construction or operation of such facilities. If the purchaser of the landfill gas is located within the
111 certificated service territory of a natural gas public utility, the public utility may file for Commission
112 approval a proposed tariff to reflect any anticipated or known changes in service to the purchaser as a
113 result of the use of landfill gas. No such tariff shall impose on the purchaser of the landfill gas terms less
114 favorable than similarly situated customers with alternative fuel capabilities; provided, however, that such
115 tariff may impose such requirements as are reasonably calculated to recover the cost of such service and
116 to protect and ensure the safety and integrity of the public utility's facilities.

117 (8) A company selling or delivering only landfill gas, electricity generated from only landfill gas,
118 or both, that is derived from a solid waste management facility permitted by the Department of
119 Environmental Quality and sold or delivered from any such facility to not more than three commercial or
120 industrial purchasers or to a natural gas or electric public utility, municipal corporation or county as
121 authorized by this section. If a purchaser of the landfill gas is located within the certificated service
122 territory of a natural gas public utility or within an area in which a municipal corporation provides gas
123 distribution service and the landfill gas is to be used in facilities constructed after January 1, 2000, such
124 company shall submit to such public utility or municipal corporation a written offer for sale of that gas
125 prior to offering the gas for sale or delivery to a commercial or industrial purchaser. If the public utility
126 or municipal corporation does not agree within 60 days following the date of the offer to purchase such
127 landfill gas on mutually satisfactory terms, then the company shall be authorized to sell such landfill gas,
128 electricity, or both, to the commercial or industrial purchaser, utility, municipal corporation, or county.
129 Such public utility may file for Commission approval a proposed tariff to reflect any anticipated or known
130 changes in service to the purchaser as a result of the purchaser's use of the landfill gas. No such tariff shall
131 impose on such purchaser of the landfill gas terms less favorable than those imposed on similarly situated
132 customers with alternative fuel capabilities; provided, however, that such tariff may impose such

133 requirements as are reasonably calculated to recover any cost of such service and to protect and ensure the
134 safety and integrity of the public utility's facilities.

135 (9) A company that is not organized as a public service company pursuant to subsection D of §
136 13.1-620 and that sells and delivers propane air only to one or more public utilities. Any company
137 excluded by this subdivision from the definition of "public utility" for the purposes of this chapter
138 nevertheless shall be subject to the Commission's jurisdiction relating to gas pipeline safety and
139 enforcement.

140 (10) A farm or aggregation of farms that owns and operates facilities within the Commonwealth
141 for the generation of electric energy from waste-to-energy technology. As used in this subdivision, (i)
142 "farm" means any person that obtains at least 51 percent of its annual gross income from agricultural
143 operations and produces the agricultural waste used as feedstock for the waste-to-energy technology, (ii)
144 "agricultural waste" means biomass waste materials capable of decomposition that are produced from the
145 raising of plants and animals during agricultural operations, including animal manures, bedding, plant
146 stalks, hulls, and vegetable matter, and (iii) "waste-to-energy technology" means any technology,
147 including a methane digester, that converts agricultural waste into gas, steam, or heat that is used to
148 generate electricity on-site.

149 (11) A company, other than an entity organized as a public service company, that provides non-
150 utility gas service as provided in § 56-265.4:6.

151 (12) A company, other than an entity organized as a public service company, that provides storage
152 of electric energy that is not for sale to the public.

153 (c) "Commission" means the State Corporation Commission.

154 (d) "Geothermal resources" means those resources as defined in § 45.2-2000.

155 **§ 56-600. Definitions.**

156 As used in this chapter:

157 "Allowed distribution revenue" means the average annual, weather-normalized, nongas
158 commodity revenue per customer associated with the rates in effect as adopted in the applicable utility's

159 last Commission-approved rate case or performance-based regulation plan, multiplied by the average
160 number of customers served.

161 "Conservation and ratemaking efficiency plan" means a plan filed by a natural gas utility pursuant
162 to this chapter that includes a decoupling mechanism.

163 "Cost-effective conservation and energy efficiency program" means a program approved by the
164 Commission that is designed to decrease the average customer's annual, weather-normalized consumption
165 ~~or total gas bill~~ of energy, for gas and nongas elements combined, or avoid energy costs or consumption
166 the customer may otherwise have incurred, and is determined by the Commission to be cost-effective if
167 the net present value of the benefits exceeds the net present value of the costs at the portfolio level as
168 determined by not less than any three of the following ~~four~~ five tests: the Total Resource Cost Test, the
169 Program Administrator Test (also referred to as the Utility Cost Test), the Participant Test, ~~and~~ the
170 Ratepayer Impact Measure Test, and the Societal Cost Test. Such determination shall include an analysis
171 of all ~~four~~ five tests, and a ~~program or~~ portfolio of programs shall be approved if the net present value of
172 the benefits exceeds the net present value of the costs as determined by not less than any three of the ~~four~~
173 five tests. Such determination shall also be made (i) with the assignment of administrative costs associated
174 with the conservation and ratemaking efficiency plan to the portfolio as a whole and (ii) with the
175 assignment of education and outreach costs associated with each program in a portfolio of programs to
176 such program and not to individual measures within a program, when such administrative, education, or
177 outreach costs are not otherwise directly assignable. Without limitation, rate designs or rate mechanisms,
178 customer education, customer incentives, appliance rebates, and weatherization programs are examples of
179 conservation and energy efficiency programs that the Commission may consider. Energy efficiency
180 programs that provide measurable and verifiable energy savings to low-income customers or elderly
181 customers may also be deemed cost effective. A cost-effective conservation and energy efficiency
182 program shall not include a program designed to convert propane or heating oil customers to natural gas.

183 "Decoupling mechanism" means a rate, tariff design or mechanism that decouples the recovery of
184 a utility's allowed distribution revenue from the level of consumption of natural gas by its customers,
185 including (i) a mechanism that adjusts actual nongas distribution revenues per customer to allowed

186 distribution revenues per customer, such as a sales adjustment clause, (ii) rate design changes that
187 substantially align the percentage of fixed charge revenue recovery with the percentage of the utility's
188 fixed costs, such as straight fixed variable rates, provided such mechanism includes a substantial demand
189 component based on a customer's peak usage, or (iii) a combination of clauses (i) and (ii) that substantially
190 decreases the relative amount of nongas distribution revenue affected by changes in per customer
191 consumption of gas.

192 "Fixed costs" means any and all of the utility's nongas costs of service, together with an authorized
193 return thereon, that are not associated with the cost of the natural gas commodity flowing through and
194 measured by the customer's meter.

195 "Measure" means an individual item, service, offering, or rebate available to a customer of a
196 natural gas utility as part of the utility's conservation and ratemaking efficiency plan.

197 "Natural gas utility" or "utility" means any investor-owned public service company engaged in the
198 business of furnishing natural gas service to the public.

199 "Portfolio" means the program or programs included in a natural gas utility's conservation and
200 ratemaking efficiency plan.

201 "Program" means a group of one or more related measures for a customer class.

202 "Revenue-neutral" means a change in a rate, tariff design or mechanism as a component of a
203 conservation and ratemaking efficiency plan that does not shift annualized allowed distribution revenue
204 between customer classes, and does not increase or decrease the utility's average, weather-normalized
205 nongas utility revenue per customer for any given rate class by more than 0.25 percent when compared to
206 (i) the rate, tariff design or mechanism in effect at the time a conservation and ratemaking efficiency plan
207 is filed pursuant to this chapter or (ii) the allocation of costs approved by the Commission in a rate case
208 using the cost of service methodology set forth in § 56-235.2 or a performance-based regulation plan
209 authorized by § 56-235.6, where a plan is filed in conjunction with such case.

210 **§ 56-601. Natural gas conservation and ratemaking efficiency.**

211 A. Consistent with the objectives pertaining to the energy issues and policy elements stated in §
212 45.2-1706.1, it is in the public interest to authorize and encourage the adoption of natural gas conservation

213 and ratemaking efficiency plans that promote the wise use of natural gas and natural gas infrastructure
214 through the development of alternative rate designs and other mechanisms that more closely align the
215 interests of natural gas utilities, their customers, and the Commonwealth generally, and improve the
216 efficiency of ratemaking to more closely reflect the dynamic nature of the natural gas market, the
217 economy, and public policy regarding conservation and energy efficiency. Such alternative rate designs
218 and other mechanisms should, where feasible:

219 1. Provide utilities with better tools to work with customers to decrease the average customer's
220 annual average weather-normalized consumption of ~~natural gas~~ energy;

221 2. Provide reasonable assurance of a utility's ability to recover costs of serving the public, including
222 its cost-effective investments in conservation and energy efficiency as well as infrastructure needed to
223 provide or maintain reliable service to the public;

224 3. ~~Reward~~ Incentivize utilities ~~for meeting or exceeding~~ to meet or exceed conservation and energy
225 efficiency goals that may be established pursuant to the Virginia Energy Plan (§ 45.2-1710 et seq.);

226 4. Provide customers with long-term, meaningful opportunities to more efficiently consume
227 ~~natural gas and mitigate their expenditures for the natural gas commodity~~ energy, while ensuring that the
228 rate design methodology used to set a utility's revenue recovery is not inconsistent with such conservation
229 and energy efficiency goals;

230 5. Recognize the economic and environmental benefits of efficient use of natural gas, biogas, and
231 lower-carbon gases; and

232 6. Preserve or enhance the utility bill savings that customers receive when they reduce their ~~natural~~
233 gas energy use.

234 B. Natural gas utilities are authorized pursuant to this chapter to file natural gas conservation and
235 ratemaking efficiency plans that implement alternative natural gas utility rate designs and other
236 mechanisms, in addition to or in conjunction with the cost of service methodology set forth in § 56-235.2
237 and performance-based regulation plans authorized by § 56-235.6, that:

238 1. Replace existing utility rate designs or other mechanisms that promote inefficient use of natural
239 gas with rate designs or other mechanisms that ensure a utility's recovery of its authorized revenues is
240 independent of the amount of customers' natural gas consumption;

241 2. Provide incentives for natural gas utilities to promote conservation and energy efficiency by
242 granting recovery of the costs associated with cost-effective conservation and energy efficiency programs;
243 and

244 3. Reward utilities that meet or exceed conservation and energy efficiency goals on a weather-
245 normalized, annualized average customer basis through the implementation of cost-effective conservation
246 and energy efficiency programs.

247 C. This chapter shall be construed liberally to accomplish these purposes.

248 **§ 56-602. Conservation and ratemaking efficiency plans.**

249 A. Notwithstanding any provision of law to the contrary, each natural gas utility shall have the
250 option to file a conservation and ratemaking efficiency plan as provided in this chapter. Such a plan may
251 include one or more residential, small commercial, or small general service classes, but shall not apply to
252 large commercial or large industrial classes of customers. Such plan shall include: (i) a normalization
253 component that removes the effect of weather from the determination of conservation and energy
254 efficiency results; (ii) a decoupling mechanism; (iii) one or more cost-effective conservation and energy
255 efficiency programs; (iv) provisions to address the needs of low-income or low-usage residential
256 customers; and (v) provisions to ensure that the rates and service to non-participating classes of customers
257 are not adversely impacted. Such plan may also include provisions for phased or targeted implementation
258 of rate or tariff design changes, if any, or conservation and energy efficiency programs. The Commission
259 may approve such a plan after such notice and opportunity for hearing as the Commission may prescribe,
260 subject to the provisions of this chapter. Nothing in this subsection shall prevent a natural gas utility from
261 amending a conservation and ratemaking efficiency plan by amending, altering, supplementing, or
262 deleting one or more conservation or energy efficiency programs.

263 B. The Commission shall approve or deny, within 180 days, a natural gas utility's initial application
264 for any revenue-neutral conservation and ratemaking efficiency plan that allocates annual per-customer

265 fixed costs on an intra-class basis in reliance upon a revenue study or class cost of service study supporting
266 the rates in effect at the time the plan is filed. A plan filed pursuant to this subsection shall not require the
267 filing of rate case schedules. The Commission shall approve or deny, within 120 days, a natural gas utility's
268 application to amend a previously approved plan. The Commission shall approve such a plan or
269 amendment if it finds that the plan's or amendment's proposed decoupling mechanism is revenue-neutral
270 and is otherwise consistent with this chapter. If the Commission denies such a plan or amendment, it shall
271 set forth with specificity the reasons for such denial and the utility shall have the right to refile, without
272 prejudice, an amended plan or amendment within 60 days, and the Commission shall thereafter have 60
273 days to approve or deny the amended plan or amendment. The time period for Commission review
274 provided for in this subsection shall not apply if the conservation and ratemaking efficiency plan is filed
275 in conjunction with a rate case using the cost of service methodology set forth in § 56-235.2 or a
276 performance-based regulation plan authorized by § 56-235.6.

277 C. The Commission shall approve or deny, within 270 days, a natural gas utility's initial application
278 for any revenue-neutral conservation and ratemaking efficiency plan that allocates per-customer fixed
279 costs on an intra-class basis according to a class cost of service study filed with the plan, when such plan
280 is filed in conjunction with a rate case using the cost of service methodology set forth in § 56-235.2 or a
281 performance-based regulation plan authorized by § 56-235.6. The Commission shall approve or deny,
282 within 120 days, a natural gas utility's application to amend a plan previously approved pursuant to this
283 subsection. The Commission shall approve such a plan or amendment if it finds that the plan's or
284 amendment's proposed decoupling mechanism is revenue-neutral, is consistent with this chapter, and is
285 otherwise in the public interest, including any findings required by § 56-235.2 or 56-235.6. If the
286 Commission denies such a plan or amendment, it shall set forth with specificity the reasons for its denial
287 and the utility shall have the right to refile, without prejudice, an amended plan or amendment within 60
288 days; the Commission shall thereafter have 60 days to approve or deny the amended plan or amendment.

289 D. The Commission shall allow any natural gas utility that implements a conservation and
290 ratemaking efficiency plan under this chapter to recover, on a timely basis and through its regulated rates
291 charged to its classes of customers participating in the plan, its entire incremental costs associated with

292 cost-effective conservation and energy efficiency programs that are designed to encourage the reduction
293 of annualized, weather-normalized ~~natural gas~~ energy consumption per customer. Ratemaking treatment
294 may include placing appropriate capital expenditures for technology and program costs in the respective
295 utility's rate base, deferral of such interim incremental costs (which costs would not be subject to an
296 earnings test), or recovering the utility's technology and program costs through another ratemaking
297 methodology approved by the Commission, such as a tracking mechanism. Such conservation and energy
298 efficiency programs may also be jointly conducted or co-sponsored with other utilities, federal, state or
299 local government agencies, nonprofit organizations, trade associations, homebuilders, and other for-profit
300 vendors. Incremental costs recovered pursuant to this subsection shall be in addition to all other costs that
301 the utility is permitted to recover, shall not be considered an offset to other Commission-approved costs
302 of service or revenue requirements, and shall not be included in any computation relative to a performance-
303 based regulation plan revenue sharing mechanism.

304 E. The Commission shall require every natural gas utility operating under a conservation and
305 ratemaking efficiency plan approved pursuant to this chapter to file annual reports showing the year over
306 year weather-normalized use of ~~natural gas~~ energy on an average customer basis, by customer class, as
307 well as the incremental, independently verified net economic benefits created by the utility's cost-effective
308 conservation and energy-efficiency programs during the previous year.

309 F. The Commission shall grant recovery, on an annual basis, of a performance-based incentive for
310 delivering conservation and energy efficiency benefits, which shall be included in the utility's respective
311 purchased gas adjustment mechanism. The incentive shall be calculated as a reasonable share of the
312 verified net economic benefits created by the utility's cost-effective conservation and energy efficiency
313 programs, and may be recovered over a period of years equal to the payback period or discounted to net
314 present value and recovered in the first year. In structuring this incentive, the Commission shall create a
315 reasonable opportunity for a utility to earn up to a 15 percent share of such independently verified net
316 economic benefits upon meeting target levels of such benefits set forth in a plan approved by the
317 Commission. The level of net economic benefits to be used as the basis for such calculation shall be the
318 sum of customer savings less utility costs recovered through subsection D, measured over the number of

319 years of the payback period, rounded up to the next highest year. The incentives authorized by this
320 subsection shall be in addition to any other revenue requirements or rates established pursuant to § 56-
321 235.2 or 56-235.6 and independent of any computation of shared revenues under an approved
322 performance-based regulation plan.

323 G. Unless the context clearly indicates otherwise, nothing in this chapter shall impair the
324 Commission's authority under § 56-234.2, 56-235.2, or 56-235.6; provided, however, that notwithstanding
325 any other provision of law, the Commission shall not reduce an authorized return on common equity or
326 other measure of utility profit as a result of the implementation of a natural gas conservation and
327 ratemaking efficiency plan pursuant to this chapter.

328 **§ 56-603. Definitions.**

329 As used in this chapter:

330 "Commission" means the State Corporation Commission.

331 "Eligible infrastructure replacement" means natural gas utility facility replacement projects that:
332 (i) enhance safety or reliability by reducing system integrity risks associated with customer outages,
333 corrosion, equipment failures, material failures, or natural forces; (ii) do not increase revenues by directly
334 connecting the infrastructure replacement to new customers; (iii) reduce or have the potential to reduce
335 greenhouse gas emissions; (iv) are commenced on or after January 1, 2010; and (v) are not included in the
336 natural gas utility's rate base in its most recent rate case using the cost of service methodology set forth in
337 § 56-235.2, or the natural gas utility's rate base included in the rate base schedules filed with a
338 performance-based regulation plan authorized by § 56-235.6, if the plan did not include the rate base.

339 "Eligible infrastructure replacement" includes natural gas utility facility replacement projects that are
340 identified as a result of an enhanced leak detection and repair program.

341 "Eligible infrastructure replacement costs" includes the following:

342 1. Return on the investment. In calculating the return on the investment, the Commission shall use
343 the natural gas utility's regulatory capital structure as calculated utilizing the weighted average cost of
344 capital, including the cost of debt and the cost of equity used in determining the natural gas utility's base
345 rates in effect during the construction period of the eligible infrastructure replacement project. If the

346 natural gas utility's cost of capital underlying the base rates in effect at the time its proposed SAVE plan
347 is filed has not been changed by order of the Commission within the preceding five years, the Commission
348 may require the natural gas utility to file an updated weighted average cost of capital, and the natural gas
349 utility may propose an updated weighted average cost of capital. The natural gas utility may recover the
350 external costs associated with establishing its updated weighted average cost of capital through the SAVE
351 rider. Such external costs shall include legal costs and consultant costs;

352 2. A revenue conversion factor, including income taxes and an allowance for bad debt expense,
353 shall be applied to the required operating income resulting from the eligible infrastructure replacement
354 costs;

355 3. Depreciation. In calculating depreciation, the Commission shall use the natural gas utility's
356 current depreciation rates;

357 4. Property taxes;~~and~~

358 5. Carrying costs on the over- or under-recovery of the eligible infrastructure replacement costs.
359 In calculating the carrying costs, the Commission shall use the natural gas utility's regulatory capital
360 structure as determined in subdivision 1 of the definition of eligible infrastructure replacement costs; and

361 6. Enhanced leak detection and repair program costs. Such costs shall include the costs of operating
362 an enhanced leak detection and repair program.

363 "Enhanced leak detection and repair program" means a program that is designed to allow a natural
364 gas utility to deploy advanced leak detection technologies to more accurately identify active leaks as part
365 of the natural gas utility's leak management program and to prioritize the repair of leaks that present a risk
366 to safety or the environment. A natural gas utility may amend its SAVE plan to include an enhanced leak
367 detection and repair program by filing an application to amend its previously approved SAVE plan, as set
368 forth in subsection B of § 56-604.

369 "Investment" means costs incurred on eligible infrastructure replacement projects including
370 planning, development, and construction costs; costs of infrastructure associated therewith; and an
371 allowance for funds used during construction. In calculating the allowance for funds used during

372 construction, the Commission shall use the natural gas utility's actual regulatory capital structure as
373 determined in subdivision 1 of the definition of eligible infrastructure replacement costs.

374 "Natural gas utility" means any investor-owned public service company engaged in the business
375 of furnishing natural gas service to the public.

376 "Natural gas utility facility replacement project" means the replacement of storage, peak shaving,
377 transmission or distribution facilities used in the delivery of natural gas, or supplemental or substitute
378 forms of gas sources by a natural gas utility.

379 "SAVE" means Steps to Advance Virginia's Energy Plan.

380 "SAVE plan" means a plan filed by a natural gas utility that identifies proposed eligible
381 infrastructure replacement projects and a SAVE rider.

382 "SAVE rider" means a recovery mechanism that will allow for recovery of the eligible
383 infrastructure replacement costs, through a separate mechanism from the customer rates established in a
384 rate case using the cost of service methodology set forth in § 56-235.2, or a performance-based regulation
385 plan authorized by § 56-235.6.

386 **§ 56-604. Filing of petition with Commission to establish or amend a SAVE plan; recovery**
387 **of certain costs; procedure.**

388 A. Notwithstanding any provisions of law to the contrary, a natural gas utility may file a SAVE
389 plan as provided in this chapter. Such a plan shall provide for a timeline for completion of the proposed
390 eligible infrastructure replacement projects, the estimated costs of the proposed eligible infrastructure
391 projects, and a schedule for recovery of the related eligible infrastructure replacement costs through the
392 SAVE rider, and demonstrate that the plan is prudent and reasonable. Such a plan may also include an
393 enhanced leak detection and repair program, which shall include a description and an estimate of the
394 associated enhanced leak detection and repair program costs. The Commission may approve such a plan
395 after such notice and opportunity for hearing as the Commission may prescribe, subject to the provisions
396 of this chapter.

397 B. The Commission shall approve or deny, within 180 days, a natural gas utility's initial application
398 for a SAVE plan. A plan filed pursuant to this section shall not require the filing of rate case schedules.

399 The Commission shall approve or deny, within 120 days, a natural gas utility's application to amend a
400 previously approved plan. If the Commission denies such a plan or amendment, it shall set forth with
401 specificity the reasons for such denial, and the utility shall have the right to refile, without prejudice, an
402 amended plan or amendment within 60 days, and the Commission shall thereafter have 60 days to approve
403 or deny the amended plan or amendment. The time period for Commission review provided for in this
404 subsection shall not apply if the SAVE plan is filed in conjunction with a rate case using the cost of service
405 methodology set forth in § 56-235.2, or a performance-based regulation plan authorized by § 56-235.6.

406 C. Any SAVE plan and any SAVE rider that is submitted to and approved by the Commission
407 shall be allocated and charged in accordance with appropriate cost causation principles in order to avoid
408 any undue cross-subsidization between rate classes.

409 D. No other revenue requirement or ratemaking issues may be examined in consideration of the
410 application filed pursuant to the provisions of this chapter.

411 E. At the end of each 12-month period the SAVE rider is in effect, the natural gas utility shall
412 reconcile the difference between the recognized eligible infrastructure replacement costs and the amounts
413 recovered under the SAVE rider, and shall submit the reconciliation and a proposed SAVE rider
414 adjustment to the Commission to recover or refund the difference, as appropriate, through an adjustment
415 to the SAVE rider. The Commission shall approve or deny, within 90 days, a natural gas utility's proposed
416 SAVE rider adjustment.

417 F. A natural gas utility that has implemented a SAVE rider pursuant to this chapter shall file revised
418 rate schedules to reset the SAVE rider to zero, when new base rates and charges that incorporate eligible
419 infrastructure replacement costs previously reflected in the currently effective SAVE rider become
420 effective for the natural gas utility, following a Commission order establishing customer rates in a rate
421 case using the cost of service methodology set forth in § 56-235.2, or a performance-based regulation plan
422 authorized by § 56-235.6.

423 G. Costs recovered pursuant to this chapter shall be in addition to all other costs that the natural
424 gas utility is permitted to recover, shall not be considered an offset to other Commission-approved costs
425 of service or revenue requirements, and shall not be included in any computation relative to a performance-

426 based regulation plan revenue-sharing mechanism. Further, if the Commission approves (i) an updated
427 weighted average cost of capital for use in calculating the return on investment, (ii) the carrying costs on
428 the over- or under-recovery of the eligible infrastructure replacement costs, (iii) the allowance for funds
429 used during construction, or (iv) any combination thereof, such weighted average cost of capital shall be
430 used only for the purpose of the eligible infrastructure replacement costs for the SAVE rider and shall not
431 be used for any purpose in any other proceeding.

432 CHAPTER 30.

433 BIOGAS SUPPLY INFRASTRUCTURE PROJECTS.

434 **§ 56-625. Biogas supply infrastructure projects.**

435 A. As used in this section:

436 "Biogas" has the same meaning as set forth in § 56-248.1.

437 "Biogas reserves and upstream pipelines and facilities" means investments in biogas reserves;
438 production facilities, including equipment required to prepare the biogas for use; gathering of,
439 transmission of, and, within the natural gas utility's certificated service territory, any distribution pipelines
440 necessary to deliver the reserves; and aboveground and underground storage used in the delivery of gas
441 to existing natural gas transmission pipelines or distribution systems.

442 "Biogas supply investment plan" means a plan filed by a natural gas utility that identifies proposed
443 eligible biogas supply infrastructure projects and its development of those projects with or without a third
444 party.

445 "Eligible biogas supply infrastructure costs" includes the investment in eligible biogas supply
446 infrastructure projects and the following:

447 1. Return on the investment. In calculating the return on the investment, the Commission shall use
448 the natural gas utility's regulatory capital structure used in determining the natural gas utility's base rates
449 in effect during the construction period of the biogas supply infrastructure project. The regulatory capital
450 structure shall be calculated utilizing the weighted average cost of capital, including the cost of debt and
451 the cost of equity, plus an additional 100 basis points added to the cost of equity. If the natural gas utility's
452 cost of capital underlying the base rates in effect at the time its proposed biogas supply infrastructure

453 project is filed has not been changed by order of the Commission within the preceding five years, the
454 Commission may require the natural gas utility to file an updated weighted average cost of capital, and
455 the natural gas utility may propose an updated weighted average cost of capital. The natural gas utility
456 may recover the external costs associated with establishing its updated weighted average cost of capital
457 through a biogas supply rider. Such external costs shall include legal costs and consultant costs;

458 2. A revenue conversion factor. Such factor, including income taxes, shall be applied to the
459 required operating income resulting from the eligible biogas supply infrastructure costs;

460 3. Operating and maintenance expenses. These expenses include the amount of operating and
461 maintenance expenses utilized in biogas collection; processing the gas produced; and gathering,
462 transmission, and distribution lines delivering the gas to a pipeline or distribution system;

463 4. Depreciation. In calculating depreciation, the Commission shall use the natural gas utility's
464 current depreciation rates for investments in distribution infrastructure, as set out by the appropriate asset
465 class. The natural gas utility shall propose a basis for recovering for the depreciation or depletion of
466 investments in other asset classes in the biogas supply investment plan, including investments in biogas
467 reserves that will deplete based on their useful life or of associated facilities that may be retired upon
468 depletion of biogas reserves;

469 5. Property tax and any other taxes or government fees associated with production and transmission
470 of biogas; and

471 6. Carrying costs on the over-recovery or under-recovery of the eligible biogas supply
472 infrastructure costs. In calculating the carrying costs, the Commission shall use the natural gas utility's
473 regulatory capital structure as determined in subdivision 1.

474 "Eligible biogas supply infrastructure projects" means capital investments in biogas facilities that,
475 alone or in combination with other projects or strategies, offer reasonably anticipated benefits to customers
476 and markets, which benefits mean (i) a reduction in methane or carbon dioxide equivalent emissions from
477 the biogas facility, (ii) an additional source of supply for the natural gas utility, (iii) a beneficial use for
478 the biogas, and which benefits do not result in the gas delivered to customers failing to meet the natural
479 gas utility's pipeline quality standards.

480 "Investment" means actual costs incurred on eligible biogas supply infrastructure projects,
481 including planning, development, and construction costs; actual costs of infrastructure associated
482 therewith; and an allowance for funds used during construction. In calculating the allowance for funds
483 used during construction, the Commission shall use the natural gas utility's actual regulatory capital
484 structure as determined in subdivision 1 of the definition of "eligible biogas supply infrastructure costs."

485 B. A natural gas utility shall have the right to recover eligible biogas supply infrastructure costs
486 on an ongoing basis through the gas cost component of the natural gas utility's rate structure or other
487 recovery mechanism approved by the Commission, provided that any such mechanism shall properly
488 allocate costs. Natural gas utilities using the cost of service methodology set forth in § 56-235.2 or a
489 performance-based regulation plan authorized by § 56-235.6 shall be eligible to file a plan. The plan shall
490 include a timeline for the investment and completion of the proposed eligible biogas supply infrastructure
491 projects; provide for an estimated schedule for recovery of the related eligible biogas supply infrastructure
492 costs through the gas cost component of the natural gas utility's rate structure or other mechanism,
493 including proposed depreciation rates for investments in non-distribution asset classes and how any
494 revenue gains from the use of the pipelines by third parties will be used to offset eligible biogas supply
495 infrastructure costs; and demonstrate that the plan is in the public interest with due consideration to the
496 reduction in methane emissions and the addition of a supply source for the natural gas utility or a
497 combination thereof. No project may provide an annual volume of biogas that exceeds three percent of
498 the natural gas utility's annual firm sales demand, and no combination of projects may provide an annual
499 volume of biogas that exceeds 15 percent of the natural gas utility's annual firm sales demand. The natural
500 gas utility's weather-normalized firm sales demand for the calendar year preceding the application shall
501 be deemed to establish the annual firm sales demand for the purposes of calculating the volume and
502 volumetric limits of projects. The Commission shall approve such a plan upon a finding that it (i) is in the
503 public interest, (ii) will result in a decrease of methane or carbon dioxide equivalent emissions, and (iii)
504 will result in rates that are just and reasonable, after notice and an opportunity for a hearing in accordance
505 with the provisions of this chapter.

506 C. In addition to the items included in the plan as specified in subsection B, the plan may provide
507 the natural gas utility with an option to receive the biogas or sell the biogas at market prices. A natural gas
508 utility proposing this option as part of its plan shall propose how any revenue gains from the sale of the
509 biogas will be used to reduce the cost of gas to its customers. The Commission shall approve or deny,
510 within 180 days, a natural gas utility's initial application for a biogas supply infrastructure plan. A plan
511 filed pursuant to this section shall not require the filing of rate case schedules. The Commission shall
512 approve or deny, within 120 days, a natural gas utility's application to amend a previously approved plan.
513 If the Commission denies such a plan or amendment, it shall set forth with specificity the reasons for such
514 denial, and the natural gas utility shall have the right to refile, without prejudice, an amended plan or
515 amendment within 60 days, and the Commission shall thereafter have 60 days to approve or deny the
516 amended plan or amendment. If the plan is filed as part of a general rate case using the cost of service
517 methodology set forth in § 56-235.2 or a performance-based regulation plan authorized by § 56-235.6,
518 then the Commission shall approve or deny the plan concurrent with or as part of the general rate case
519 decision.

520 D. No other revenue requirement or ratemaking issues shall be examined in consideration of a plan
521 filed pursuant to the provisions of this section.

522 E. A natural gas utility with an approved biogas supply infrastructure plan shall annually file a
523 report of the eligible biogas supply infrastructure investment made, the eligible biogas supply
524 infrastructure costs incurred and the amount of such costs recovered, the volume of biogas delivered to
525 customers or sold to third parties during the 12-month reporting period, and an analysis of the price of
526 biogas delivered to the natural gas utility customers and the market cost of gas during the 12-month period.
527 However, such analysis shall not affect a natural gas utility's right to recover all eligible biogas supply
528 infrastructure costs as set forth in subsection B. The report shall also identify the balance of over-recovery
529 or under-recovery of the eligible biogas supply infrastructure costs at the end of the reporting period and
530 the projected investment to be made, the projected infrastructure costs to be incurred, and the projected
531 costs to be recovered during the next 12-month reporting period.

532 F. Costs recovered pursuant to this section shall be in addition to all other costs that the natural gas
533 utility is permitted to recover and shall not be considered an offset to other Commission-approved costs
534 of service or revenue requirements.

535 **2. That the State Corporation Commission may exempt customer education components from the**
536 **required test parameters set forth in § 56-600 of the Code of Virginia, as amended by this act, for a**
537 **conservation and energy efficiency program.**

538 **3. That each natural gas utility that has one or more State Corporation Commission-approved (the**
539 **Commission) eligible biogas supply infrastructure projects, as defined in § 56-625 of the Code of**
540 **Virginia, as created by this act, shall report annually to the Commission the reduction in methane**
541 **and carbon dioxide equivalent emissions from each such approved project. The Commission shall**
542 **issue an annual report describing the number of approved eligible biogas supply infrastructure**
543 **projects, as defined in § 56-625 of the Code of Virginia, as created by this act, and the methane and**
544 **carbon dioxide equivalent emissions from such approved projects. The Commission shall make such**
545 **report available on its website.**

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