COMMONWEALTH OF VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY

CONTROLLING METHANE FROM NATURAL GAS INFRASTRUCTURE SB565 WORKGROUP, MEETING MINUTES

MAY 11, 2023

Members Present:
Braven Beaty, The Nature Conservancy
James Bradbury, Georgetown Climate
Greg Buppert (for Will Cleveland), SELC
Andres Clarens, UVA
Stephen Holcomb, NiSource
Jon Lawson, EnerVest
Tommy Oliver, Roanoke Gas
Zachery Smith (for Joshua Ball) CNX
Jeff Zehner (for Lisa S. Beal), BHE

Members Absent:
Dan Grossman (Jon Goldstein), EDF
Richard Lutz, Transco

Staff:
Department of Environmental Quality, Air & Renewable Energy Division
Michael G. Dowd, Director
Karen Sabasteanski
Tamera Thompson

The meeting began at approximately 10:05 a.m.

Meeting Purpose: This workgroup has been established to advise and assist DEQ in meeting the requirements of SB565 (Chapter 728, see Attachment A), requiring DEQ to convene a work group of stakeholders to determine the feasibility of setting a statewide methane reduction goal and plan to achieve the same, (see enactment clause 4 on the last page). The agenda is found in Attachment B.

Welcome, Summary, Introductions: Mr. Dowd welcomed the group. Members introduced themselves individually. Ms. Sabasteanski briefly summarized Virginia Freedom of Information Act (FOIA) requirements as they pertain to this meetings. She then provided a brief overview of the history of methane studies in which the group had participated in the past, and summarized current federal and state requirements. A copy of the presentation is found in Attachment C.

Group Discussion: The group provided the views of their organizations regarding the following general topics.

There is a need for better data and monitoring in order to better understand where the main emitters are located and the nature of key leakage sites, in order to better understand and target needed reductions. Identifying and repairing leaks is cost-effective, and the technology exists to address most problems.

Addressing methane in the short term is urgent. But in the long term, the broadest possible approach --whether renewable natural gas and other infrastructure technology innovations--may ultimately lead to a "post-natural gas/methane world."

The political nature of policymaking may make it difficult to rely on consistent federal and state rules, and whether it is possible to control reliability of policy. Some participants would support a non-regulatory state methane control goal or target--a goal that may or may not track with federal actions, but would be a stopgap in the event federal actions fail, and would in any event contribute to pre-existing state climate goals.

Some participants believe that the proposed U.S. Environmental Protection Agency (EPA) rules for this sector are adequate and will address outstanding applicability concerns, some do not; those who do not were encouraged to share their specific concerns. In addition to EPA rules, it was noted that on May 5, 2023, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration’s (PHMSA) proposed regulatory amendments that implement the 2020 Protecting Our Infrastructure of Pipelines and Enhancing Safety Act to reduce methane emissions from new and existing pipelines, storage facilities, and liquefied natural gas facilities. There are several ongoing federal programs designed to control methane and greenhouse gas pollution overall, but it is difficult to gauge whether or not it is best to wait for the federal programs, or to move ahead at the state level.

Impacts on equity and human health should be considered. Federal rules do not address indoor air quality, health, or disproportionate impacts. State and local governments may be better positioned to address these issues, and Inflation Reduction Act (IRA) and Bipartisan Infrastructure Law (BIL) funds may provide funding for additional controls at the local/community level. More aggressive steps need to be taken in order to "make it happen" instead of waiting for federal action--what flexibilities, incentives, support (such as low interest loans) will fill in the gaps?

Local gas distribution companies have been acting to reduce emissions while expanding services. One company has already begun participation in the HB565 program to produce commercial quality renewable natural gas from biogas produced at a wastewater treatment plant. The production, processing, and transmission sectors have also sought to reduce leakage, and has engaged drone and satellite surveys to identify and repair leaks. The IRA and BIL may provide additional funding for leak identification and control projects. Various voluntary controls are also available, such as "certified" natural gas that is certified by a third party to be responsibly obtained and that there are zero transmission leaks.

Other sectors, such as agriculture, coal mining, and landfills were identified as needing additional attention and study.

Finally, the group discussed the overall concept of whether certain controls meet the criteria of being "feasible," that is, whether or not a control is practical and technically possible, and how these controls should be sequenced with others.

Wrap-up: Ms. Sabasteanski concluded the meeting. Minutes will be posted to Town Hall, and all materials shared with the group will be posted on the DEQ methane web page: https://www.deq.virginia.gov/air/greenhouse-gases/methane.

The meeting adjourned at approximately 11:30 a.m.

Attachments
REG\DEV\methane minutes

VIRGINIA ACTS OF ASSEMBLY -- 2022 RECONVENED SESSION

CHAPTER 728

An Act 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.

[S 565]

Approved April 27, 2022

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:

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

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

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

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

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

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

D. This section shall not apply to telephone companies.

§ 56-265.1. Definitions.

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

(a) "Company" means a corporation, a limited liability company, an individual, a partnership, an association, a joint-stock company, a business trust, a cooperative, or an organized group of persons, whether incorporated or not; or any receiver, trustee or other liquidating agent of any of the foregoing in his capacity as such; but not a municipal corporation or a county, unless such municipal corporation or county has obtained a certificate pursuant to § 56-265.4:4.

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

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

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

(3) Any company (A) which furnishes electric service together with heating and cooling services, generated at a central plant installed on the premises to be served, to the tenants of a building or buildings located on a single tract of land undivided by any publicly maintained highway, street or road at the time of installation of the central plant, and (B) which does not charge separately or by meter for electric energy used by any tenant except as part of a rental charge. Any company excluded by this subdivision from the definition of "public utility" for the purposes of this chapter nevertheless shall, within 30 days following the issuance of a building permit, notify the State Corporation Commission in writing of the ownership, capacity and location of such central plant, and it shall be subject, with regard to the quality of electric service furnished, to the provisions of Chapters 10 (§ 56-232 et seq.) and 17 (§ 56-509 et seq.) and regulations thereunder and be deemed a public utility for such purposes, if such company furnishes such service to 100 or more lessees.

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

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

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

(7) Any authority created pursuant to the Virginia Water and Waste Authorities Act (§ 15.2-5100 et seq.) making a sale or ancillary transmission or delivery service of landfill gas to a commercial or industrial customer from a solid waste management facility permitted by the Department of Environmental Quality and operated by that same authority, if such an authority limits off-premises sale, transmission or delivery service of landfill gas to no more than one purchaser. The authority may contract with other persons for the construction and operation of facilities necessary or convenient to the sale, transmission or delivery of landfill gas, and no such person shall be deemed a public utility solely by reason of its construction or operation of such facilities. If the purchaser of the landfill gas is located within the certificated service territory of a natural gas public utility, the public utility may file for Commission approval a proposed tariff to reflect any anticipated or known changes in service to the purchaser as a result of the use of landfill gas. No such tariff shall impose on the purchaser of the landfill gas terms less favorable than similarly situated customers with alternative fuel capabilities; provided, however, that such tariff may impose such requirements as are reasonably calculated to recover the cost of such service and to protect and ensure the safety and integrity of the public utility's facilities.

(8) A company selling or delivering only landfill gas, electricity generated from only landfill gas, or both, that is derived from a solid waste management facility permitted by the Department of Environmental Quality and sold or delivered from any such facility to not more than three commercial or industrial purchasers or to a natural gas or electric public utility, municipal corporation or county as authorized by this section. If a purchaser of the landfill gas is located within the certificated service

territory of a natural gas public utility or within an area in which a municipal corporation provides gas distribution service and the landfill gas is to be used in facilities constructed after January 1, 2000, such company shall submit to such public utility or municipal corporation a written offer for sale of that gas prior to offering the gas for sale or delivery to a commercial or industrial purchaser. If the public utility or municipal corporation does not agree within 60 days following the date of the offer to purchase such landfill gas on mutually satisfactory terms, then the company shall be authorized to sell such landfill gas, electricity, or both, to the commercial or industrial purchaser, utility, municipal corporation, or county. Such public utility may file for Commission approval a proposed tariff to reflect any anticipated or known changes in service to the purchaser as a result of the purchaser's use of the landfill gas. No such tariff shall impose on such purchaser of the landfill gas terms less favorable than those imposed on similarly situated customers with alternative fuel capabilities; provided, however, that such tariff may impose such requirements as are reasonably calculated to recover any cost of such service and to protect and ensure the safety and integrity of the public utility's facilities.

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

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

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

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

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

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

§ 56-600. Definitions.

As used in this chapter:

"Allowed distribution revenue" means the average annual, weather-normalized, nongas commodity revenue per customer associated with the rates in effect as adopted in the applicable utility's last Commission-approved rate case or performance-based regulation plan, multiplied by the average number of customers served.

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

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

"Decoupling mechanism" means a rate, tariff design or mechanism that decouples the recovery of a utility's allowed distribution revenue from the level of consumption of natural gas by its customers, including (i) a mechanism that adjusts actual nongas distribution revenues per customer to allowed distribution revenues per customer, such as a sales adjustment clause, (ii) rate design changes that substantially align the percentage of fixed charge revenue recovery with the percentage of the utility's fixed costs, such as straight fixed variable rates, provided such mechanism includes a substantial demand component based on a customer's peak usage, or (iii) a combination of clauses (i) and (ii) that substantially decreases the relative amount of nongas distribution revenue affected by changes in per customer consumption of gas.

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

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

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

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

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

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

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

A. Consistent with the objectives pertaining to the energy issues and policy elements stated in § 45.2-1706.1, it is in the public interest to authorize and encourage the adoption of natural gas conservation and ratemaking efficiency plans that promote the wise use of natural gas and natural gas infrastructure through the development of alternative rate designs and other mechanisms that more closely align the interests of natural gas utilities, their customers, and the Commonwealth generally, and improve the efficiency of ratemaking to more closely reflect the dynamic nature of the natural gas market, the economy, and public policy regarding conservation and energy efficiency. Such alternative rate designs and other mechanisms should, where feasible:

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

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

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

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

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

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

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

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

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

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

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

§ 56-602. Conservation and ratemaking efficiency plans.

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

B. The Commission shall approve or deny, within 180 days, a natural gas utility's initial application for any revenue-neutral conservation and ratemaking efficiency plan that allocates annual per-customer fixed costs on an intra-class basis in reliance upon a revenue study or class cost of service study supporting the rates in effect at the time the plan is filed. A plan filed pursuant to this subsection shall not require the filing of rate case schedules. The Commission shall approve or deny, within 120 days, a natural gas utility's application to amend a previously approved plan. The Commission shall approve such a plan or amendment if it finds that the plan's or amendment's proposed decoupling mechanism is revenue-neutral and is otherwise consistent with this chapter. If the Commission denies such a plan or amendment, it shall set forth with specificity the reasons for such denial and the utility shall have the right to refile, without prejudice, an amended plan or amendment within 60 days, and the Commission shall thereafter have 60 days to approve or deny the amended plan or amendment. The time period for Commission review provided for in this subsection shall not apply if the conservation and ratemaking efficiency plan is filed in conjunction with a rate case using the cost of service methodology set forth in § 56-235.2 or a performance-based regulation plan authorized by § 56-235.6.

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

D. The Commission shall allow any natural gas utility that implements a conservation and ratemaking efficiency plan under this chapter to recover, on a timely basis and through its regulated rates charged to its classes of customers participating in the plan, its entire incremental costs associated with cost-effective conservation and energy efficiency programs that are designed to encourage the reduction of annualized, weather-normalized ~~natural~~ ~~gas~~ *energy* consumption per customer. Ratemaking treatment may include placing appropriate capital expenditures for technology and program costs in the respective utility's rate base, deferral of such interim incremental costs (which costs would not be subject to an earnings test), or recovering the utility's technology and program costs through another ratemaking methodology approved by the Commission, such as a tracking mechanism. Such conservation and energy efficiency programs may also be jointly conducted or co-sponsored with other utilities, federal, state or local government agencies, nonprofit organizations, trade associations, homebuilders, and other for-profit vendors. Incremental costs recovered pursuant to this subsection shall be in addition to all other costs that the utility is permitted to recover, shall not be considered an offset to other Commission-approved costs of service or revenue requirements, and shall not be included in any computation relative to a performance-based regulation plan revenue sharing mechanism.

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

F. The Commission shall grant recovery, on an annual basis, of a performance-based incentive for delivering conservation and energy efficiency benefits, which shall be included in the utility's respective purchased gas adjustment mechanism. The incentive shall be calculated as a reasonable share of the verified net economic benefits created by the utility's cost-effective conservation and energy efficiency programs, and may be recovered over a period of years equal to the payback period or discounted to net present value and recovered in the first year. In structuring this incentive, the Commission shall create a reasonable opportunity for a utility to earn up to a 15 percent share of such independently verified net economic benefits upon meeting target levels of such benefits set forth in a plan approved by the Commission. The level of net economic benefits to be used as the basis for such calculation shall be the sum of customer savings less utility costs recovered through subsection D, measured over the number of years of the payback period, rounded up to the next highest year. The incentives authorized by this subsection shall be in addition to any other revenue requirements or rates established pursuant to § 56-235.2 or 56-235.6 and independent of any computation of shared revenues under an approved performance-based regulation plan.

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

§ 56-603. Definitions.

As used in this chapter:

"Commission" means the State Corporation Commission.

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

"Eligible infrastructure replacement costs" includes the following:

1. Return on the investment. In calculating the return on the investment, the Commission shall use the natural gas utility's regulatory capital structure as calculated utilizing the weighted average cost of capital, including the cost of debt and the cost of equity used in determining the natural gas utility's base rates in effect during the construction period of the eligible infrastructure replacement project. If the natural gas utility's cost of capital underlying the base rates in effect at the time its proposed SAVE plan is filed has not been changed by order of the Commission within the preceding five years, the Commission may require the natural gas utility to file an updated weighted average cost of capital, and the natural gas utility may propose an updated weighted average cost of capital. The natural gas utility may recover the external costs associated with establishing its updated weighted average cost of capital through the SAVE rider. Such external costs shall include legal costs and consultant costs;

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

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

4. Property taxes; ~~and~~

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

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

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

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

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

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

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

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

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

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

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

B. The Commission shall approve or deny, within 180 days, a natural gas utility's initial application for a SAVE plan. A plan filed pursuant to this section shall not require the filing of rate case schedules. The Commission shall approve or deny, within 120 days, a natural gas utility's application to amend a previously approved plan. If the Commission denies such a plan or amendment, it shall set forth with specificity the reasons for such denial, and the utility shall have the right to refile, without prejudice, an amended plan or amendment within 60 days, and the Commission shall thereafter have 60 days to approve or deny the amended plan or amendment. The time period for Commission review provided for in this subsection shall not apply if the SAVE plan is filed in conjunction with a rate case using the cost of service methodology set forth in § 56-235.2, or a performance-based regulation plan authorized by § 56-235.6.

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

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

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

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

G. Costs recovered pursuant to this chapter shall be in addition to all other costs that the natural gas utility is permitted to recover, shall not be considered an offset to other Commission-approved costs of service or revenue requirements, and shall not be included in any computation relative to a performance-based regulation plan revenue-sharing mechanism. Further, if the Commission approves (i) an updated weighted average cost of capital for use in calculating the return on investment, (ii) the carrying costs on the over- or under-recovery of the eligible infrastructure replacement costs, (iii) the allowance for funds used during construction, or (iv) any combination thereof, such weighted average cost of capital shall be used only for the purpose of the eligible infrastructure replacement costs for the SAVE rider and shall not be used for any purpose in any other proceeding.

CHAPTER 30.

BIOGAS SUPPLY INFRASTRUCTURE PROJECTS.

§ 56-625. Biogas supply infrastructure projects.

A. As used in this section:

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

"Biogas facilities" means biogas reserves; production facilities, including equipment required to prepare the biogas for use; gathering of, transmission of, and, within the natural gas utility's certificated service territory, any distribution pipelines necessary to deliver the reserves; and aboveground and

underground storage used in the delivery of gas to existing natural gas transmission pipelines or distribution systems.

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

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

1. Return on the investment. In calculating the return on the investment, the Commission shall use the natural gas utility's regulatory capital structure in effect during the construction period of the eligible biogas supply infrastructure project. The regulatory capital structure shall be calculated utilizing the weighted average cost of capital, including the cost of debt and the cost of equity, plus an additional 100 basis points added to the cost of equity. If the natural gas utility's cost of capital underlying the base rates in effect at the time its proposed eligible biogas supply infrastructure project is filed has not been changed by order of the Commission within the preceding five years, the Commission may require the natural gas utility to file an updated weighted average cost of capital, and the natural gas utility may propose an updated weighted average cost of capital. The natural gas utility may recover the external costs associated with establishing its updated weighted average cost of capital through a biogas supply rider. Such external costs shall include legal costs and consultant costs;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4. That the Department of Environmental Quality (the Department) shall convene a work group of stakeholders to determine the feasibility of setting a statewide methane reduction goal and plan to achieve the same. The Department shall report its findings and recommendations to the Chairmen of the Senate Committee on Agriculture, Conservation and Natural Resources, the Senate Committee on Commerce and Labor, the House Committee on Agriculture, Chesapeake and Natural Resources, and the House Committee on Commerce and Energy by July 1, 2023.

COMMONWEALTH OF VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY

CONTROLLING METHANE FROM NATURAL GAS INFRASTRUCTURE
SB565 WORKGROUP

DRAFT AGENDA

May 11, 2023

10:00 – 10:30	WELCOME/INTRODUCTIONS
10:30 – 10:35	FOIA REQUIREMENTS
10:35 – 10:45	BRIEF BACKGROUND
10:45 – 12:00	GROUP DISCUSSION
12:00 – 12:45	BREAK
12:45 – 2:45	GROUP DISCUSSION
2:45 - 3:00	WRAP UP

SB565 Workgroup

Controlling Methane from Natural Gas Infrastructure

Air and Renewable Energy Division
Virginia Department of Environmental Quality
May 11, 2023

Welcome Back!

- This meeting is being recorded and minutes will be published on Town Hall
- Additional information is available on our methane web page:
  - https://www.deq.virginia.gov/air/greenhouse-gases/methane
- The meeting is open to the public but only workgroup members may participate
- Please mute yourself when not speaking
- Follow FOIA

Today's Agenda

10:00 – 10:30	WELCOME/INTRODUCTIONS
10:30 – 10:35	FOIA REQUIREMENTS
10:35 – 10:45	BRIEF BACKGROUND
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12:00 – 12:45	BREAK
12:45 – 2:45	GROUP DISCUSSION
2:45 - 3:00	WRAP UP

A Brief History of How We Got Here

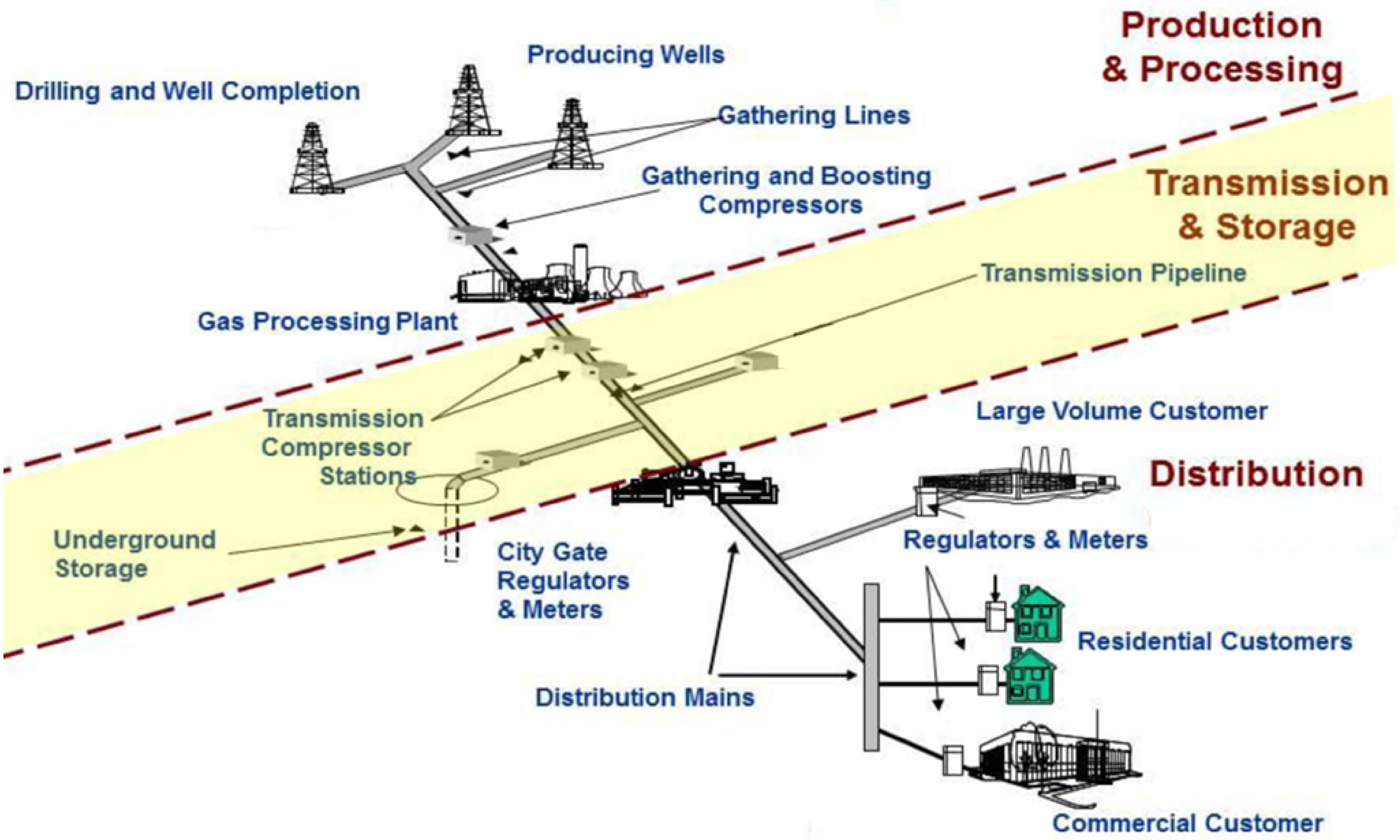
- Original charter September 2018
  - Ad Hoc Advisory Group - March-October 2019
- Official rulemaking/NOIRA April-June 2021
  - Regulatory Advisory Panel
    - On hold/cancelled
- What changed:
  - EPA proposal 11/11/22
  - EPA supplement 11/11/22 (final expected 8/23)
  - 2023 Acts of Assembly, SB565 (Chapter 728)

SB565: 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; work group.

- Natural gas conservation and energy efficiency programs; enhanced LDAR
- Biogas supply infrastructure projects
- Directs the Department of Environmental Quality to convene a stakeholder work group **to determine the feasibility of setting a statewide methane reduction goal and plan**. The recommendations of the work group shall be reported to the General Assembly by July 1, 2023.

Today's Task

- Report on positions
- General discussion
- DEQ's report


Production & Processing
Producing Wells
Drilling and Well Completion
Gathering Lines
Gathering and Boosting Compressors
Transmission & Storage
Transmission Pipeline
Gas Processing Plant
Transmission Compressor Stations
Large Volume Customer
Distribution
Underground Storage
City Gate Regulators & Meters
Regulators & Meters
Residential Customers
Distribution Mains
Commercial Customer