Jost Energy Law PC

Williams Weese Pepple & Ferguson

Aota Technical, LLC

Final Report of Best Practices

Regulatory Best Practices

In Support of

Minnesota Gas Technical Advisory Committee (GTAC)

PREPARED FOR:

DeYoung Consulting Services on behalf of GTAC

GTAC Agencies:

Minnesota Department of Natural Resources
Minnesota Department of Revenue
Minnesota Environmental Quality Board
Minnesota Department of Health
Minnesota Pollution Control Agency

PREPARED BY:

Jost Energy Law
Williams Weese Pepple & Ferguson
Aota Technical, LLC

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Abbreviations	
API	American Petroleum Institute
AST	Aboveground storage tank
AVO	Audio, visual, olfactory
BLM	Bureau of Land Management
BBLS	Barrels
BOPE	Blowout prevention equipment
CFR	Code of Federal Regulations
CO2	Carbon dioxide
CRS	Colorado Revised Statute
DNR	Minnesota Department of Natural Resources
DOR	Minnesota Department of Revenue
DSU	Drilling Spacing Unit
E&P	Exploration and production
EAW	Environmental Assessment Worksheet
ECMC	Colorado Energy & Carbon Management Commission
EPA	U.S. Environmental Protection Agency
EQB	Minnesota Environmental Quality Board
EUR	Estimated ultimate recovery
GIS	Geographic information system
GTAC	Gas Technical Advisory Committee
H2S	Hydrogen sulfide
JOA	Joint Operating Agreement
MCF	Thousand cubic feet
MDH	Minnesota Department of Health
MPCA	Minnesota Pollution Control Agency
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
OBA	Other Business Arrangement
PLSS	Public Land Survey System
PSA	Pressure swing adsorption
PSI	Pounds per square inch
POTW	Publicly owned treatment works
PTE	Potential to emit
RCRA	Resource Conservation and Recovery Act
RGU	Responsible Governmental Unit
SITLA	Utah School and Institutional Trust Lands Administration
SUA	Surface Use Agreement
TENORM	Technologically enhanced naturally occurring radioactive material
TPY	Tons per year
UIC	Underground Injection Control
USGS	U.S. Geological Survey
VOC	Volatile organic compounds

Introduction

Background

The Minnesota Gas Resources Technical Advisory Committee (GTAC) formed in response to provisions of Minnesota legislation passed in May 2024. The legislation authorized five Minnesota agencies to adopt or amend rules to govern oil and gas exploration and production in the state. The agencies are:

Department of Natural Resources (DNR)
Department of Health (MDH)
Department of Labor and Industry [supplanted by Department of Revenue (DOR)]
Environmental Quality Board (EQB)
Pollution Control Agency (MPCA)

GTAC convened in July 2024 to initiate work that will culminate in January 2025 with a report to the Minnesota legislature for the 2025 legislative session. The report will provide recommendations and proposed statutory language for a temporary framework to regulate GTAC's first priority: gas resource development in Minnesota. Specifically, GTAC focused on potential for well drilling and production for helium and hydrogen gas, with potential for associated gases, including methane. Preparation of GTAC's report includes public, stakeholder, and tribal input.

Minnesota legislative committees are expected to use the GTAC report, "*Recommendations and Statutory Language for Permitting Gas Resource Development Under a Temporary Regulatory Framework*," as the basis to enact enabling legislation for agencies to regulate gas development pending a subsequent multi-year notice and comment rulemaking, by agency, for the gas industry in Minnesota.

Preparers for the Report of Best Practices

The DNR contracted with DeYoung Consulting Services to provide organizational support to GTAC. DeYoung, on behalf of DNR, subcontracted for oil and gas sector technical support to GTAC during GTAC's development of recommendations to the legislature. The subcontractor was tasked with illuminating state precedents and example best practices for regulation of gas, including helium gas. Information was derived from oil and gas producing states across Midwestern and Rocky Mountain states. Information considered Minnesota's interest in fostering helium development in a manner protective of public health, the environment, and state fiduciary interests.

The technical support team included specialists in the regulation and permitting of helium gas wells, as well as the oil and natural gas industry more broadly. The technical support team's expertise was cross disciplinary. It included legal experts in energy, natural resource, and administrative and regulatory law; rulemaking; and oil and gas leasing, pooling, and unitization. It further included environmental regulatory specialists in regulatory development and compliance; siting; location analysis; and environmental resource analysis for helium gas and the energy sector. The subcontractor organizations are:

Jost Energy Law
Williams Weese Pepple & Ferguson
Aota Technical, LLC

Report Organization

The Report of Best Practices is organized by Minnesota agency and regulatory topic. Regulatory topics were identified in the 2024 Minnesota legislation and subsequent GTAC priorities. Information was provided for GTAC input in stages to identify, describe, research, and document regulatory topics and their context, precedents and examples, citations, and regulatory links. All of the information was derived from oil and gas producing states. The information informs and supports GTAC for GTAC's independent determination of recommendations to make for a temporary regulatory framework in Minnesota.

1.0 Minnesota Department of Natural Resources

Development Permit

1.1 When a Development Permit is Required

1. A Development Permit would be required prior to disturbing a new surface location to drill a gas well or install production equipment related to the gas well.
2. Expanding an existing location would require amendment to an approved Development Permit.
3. Exploration wells would be considered gas wells subject to a Development Permit, regardless of whether the well is used for production.
4. A seismic survey would not require a Development Permit and would be subject to state rules governing seismic surveys.
5. A stratigraphic well would not require a Development Permit and would be subject to state rules governing stratigraphic wells.
6. Either a water well or a stratigraphic well used for exploration or production of gas would require a Development Permit.
7. A stand-alone gas processing operation on a non-contiguous surface location would not require a Development Permit and would be subject to state rules governing industrial facilities.

   Based in part on Colorado Energy & Carbon Management Commission, Rule 304.a
   https://ecmc.state.co.us/documents/reg/Rules/LATEST/300%20Series%20-%20Permitting%20Process.pdf

1.2 Scope of Operations Subject to a Development Permit

1. Well pad
2. Production equipment on the well pad
3. Access road from the public road to the well pad
4. Flowline from the well pad to processing operations at another location
5. Where:
   a. Well pad is the total area disturbed for the well pad.
   b. Production equipment is surface equipment, and the flowlines on the well pad connecting the surface equipment, during the life of the well or processing operations on the pad.
   c. Flowlines also include the material and disturbance for one or more flowlines from the well pad to processing operations at another location.
   d. Processing operations are equipment to separate, purify, compress, and store gas from the well and any liquids.
   e. Processing operations can be located on the well pad as production equipment.
      1) Processing operations on another non-contiguous surface location off of the well pad would be subject instead to state rules governing industrial facilities.
   f. Pipelines from processing operations at another location would be regulated consistent with regulation of other industrial pipelines in the state.

1.3 Distinguish Surface Location Versus Downhole Operations

1. Surface location would mean the well pad and all area on the surface disturbed for the well pad, access, and flowlines.
2. Downhole operations would mean the subsurface well.
3. Surface location
    a. Colorado refers to an *Oil and Gas Location*. This means a definable area where an operator disturbs the land surface to locate an oil and gas facility. Oil and gas facility consists of equipment for exploration, production, withdrawal, treatment, or processing.
    b. Utah refers to a *Well Site*. This means the area directly disturbed during drilling and subsequent use by production facilities.
    c. Wyoming refers to *Oil and Gas Operations*. This means the surface disturbing activities associated with drilling, producing, and transporting oil and gas, including the full range of development activity from exploration through production and reclamation of the disturbed surface.
4. Well
    a. In Colorado a well means a hole drilled for the purpose of producing oil or gas [including non-hydrocarbon gases such as carbon dioxide (CO2) and helium], a Class II underground injection control (UIC) well, and certain other categories of wells.
    b. In Utah a well means an oil or gas well, or injection or disposal well. It "may not include…seismic, stratigraphic test… or other exploratory holes drilled for the purpose of obtaining geological information only."
    c. In Kansas a well means any hole or penetration of the surface for geological, geophysical, or any oil or gas activity. A gas well means a well that produces gas not associated with oil. Kansas is an example of a state that does not separately define the surface location.

Colorado Energy & Carbon Management Commission, Rule 100
https://ecmc.state.co.us/documents/reg/Rules/LATEST/100%20Series%20-%20Definitions.pdf

Utah Division of Oil, Gas and Mining, Rule 649-1
https://adminrules.utah.gov/public/rule/R649-1/Current%20Rules?searchText=R649

Kansas Corporation Commission, Rule 82-3-101
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

Wyoming Oil & Gas Conservation Commission, Rule 055.0001
https://rules.wyo.gov/Search.aspx?mode=1

1.4 Anticipated Surface Equipment and its Inclusion in Permitting

1. Potential equipment during well drilling and completion:
    a. Drill rig and completion rig
    b. Air package with compressor(s)
    c. Freshwater tank(s)
    d. Formation water tank(s)
    e. Drilling mud tank(s) and pump
    f. Drill cuttings tank(s)
    g. Separator
    h. Portable combustor

i. Pipe rack
j. Fuel tank
k. Light plant
l. Driller's trailer
m. Geology tent or trailer

2. Potential equipment during production

   a. Wellhead
   b. Two-phase separator for gas and water
   c. Produced water storage tank(s)
   d. Secondary containment for produced water storage tank(s)
   e. Combustor
   f. Pressure swing adsorption (PSA) plant

3. Operators can be required to list individual pieces of equipment anticipated to be on site during well drilling and completion.

4. Operators can be required to list individual pieces of equipment anticipated to be on site if the well goes into production.

5. Operators can be required to show the equipment on a layout in plan view or on a drawing.

1.5 Treatment of Production Facility

1. A stand-alone gas processing operation on a non-contiguous surface location would not require a Development Permit and would be subject to state rules governing industrial facilities.

2. Equipment located on the well pad during production would be regulated under the Development Permit as production equipment.

   a. Equipment may include processing operations using a two-phase separator, produced water storage tank(s), and combustor for total gas, and a PSA plant or other processing method for helium.

3. Equipment operation, mechanical integrity, maintenance, and monitoring would be regulated by the Development Permit.

4. Waste disposal would be regulated by PCA, with the option to incorporate waste management, waste disposal, and reporting provisions in the Development Permit.

5. Air emissions would be regulated by PCA through an air permit.

6. Wastewater discharges would be prohibited, with the option to incorporate spill control reporting and control provisions in the Development Permit.

7. Stormwater control would be regulated by PCA consistent with stormwater permit requirements in place in the state.

8. Regarding gas production, in Colorado at Energy & Carbon Management Commission (ECMC) Rule 430, the operator must measure and report the volume of gas produced from the lease or a production unit, measured by meter.

   Colorado Energy & Carbon Management Commission, Rule 100
   https://ecmc.state.co.us/documents/reg/Rules/LATEST/400%20Series%20-%20Operations%20and%20Reporting.pdf

9. Regarding gas *processing*, in Utah at Rule 649-6-1, the operator of a facility in which gas is conditioned for sale must file a monthly form reporting receipt, processing, and disposition of gas.

Utah Division of Oil, Gas and Mining, Rule 649-6-1
https://adminrules.utah.gov/public/rule/R649-6/Current%20Rules?searchText=R649

1.6 Requirement for Methane Gas

1. Separation for gas and any water from the formation (produced water) could occur in a two-phase separator. The separator would be part of production equipment on the well pad or at another location.
   a. Water from the separator could be routed by flowline to an aboveground storage tank for storage, liquids offloading by truck, and disposal.
   b. Total gas from the separator could be routed by flowline to a PSA plant.
   c. Separation of component gases would occur at that PSA plant.
   d. Operations may demonstrate, for example, that hydrocarbons (as methane) represent less than 5 percent of the total gas stream.
   e. Other components are likely to be helium, CO2, nitrogen, and trace gases (e.g., argon).
2. At low volumes, methane would not be expected to support a commercial pipeline for takeaway. Methane with no pipeline takeaway may be referred to as “stranded gas.”
3. Methane with no pipeline takeaway potentially can route for destruction to an enclosed combustor. The enclosed combustor would be expected to have a destruction efficiency of at least 98 percent.
   a. If supplemental fuel is required to operator the combustor, beneficial use or venting could be considered.
4. Methane with no pipeline takeaway can route for beneficial use on site as a fuel source for production equipment, where:
   a. Methane provides supply gas for the two-phase separator.
   b. Methane provides supply gas for natural gas engine generators needed to power equipment not otherwise connected to the power grid.
5. The Development Permit can document management and disposition for potential methane gas.

1.7 Term Permit Remains in Effect to Drill

1. Once approved, the Development Permit may contain a limit on the term it remains in effect for the operator to drill on the approved location.
   a. A limit on the term the permit remains in effect is intended to keep the conditions reported in the application current with respect to surrounding land uses and conditions.
2. In Colorado for example, under Rule 311.a, a permit to develop the approved location remains in effect for 3 years and expires if a well is not drilled within that time.
   a. Colorado does not approve extensions of the permit, according to Rule 311.b.
   b. New applications are subject to rules in effect at the time of submission, according to Rule 311.c.
3. Alternatively, Wyoming grants 2 years for drilling to commence under a permit to drill, according to Rule 055.0001.3, Section 8(h).
   a. Wyoming requires a new application 2 months prior to expiration and an extension fee to request a 2-year extension of the expiration date.

Colorado Energy & Carbon Management Commission, Rule 311
https://ecmc.state.co.us/documents/reg/Rules/LATEST/300%20Series%20-%20Permitting%20Process.pdf

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.3
https://rules.wyo.gov/Search.aspx?mode=1

1.8 Term Permit Remains in Effect to Produce

1. The term that a permit remains in effect before expiring is common in environmental programs, such as 5 years for a National Pollutant Discharge Elimination System (NPDES) wastewater discharge permit.
2. In the oil and gas sector, multiple states reviewed for precedent on the term a permit remains in effect demonstrate no stated term. The states reviewed include Colorado, Kansas, Michigan, Montana, and Wyoming.
3. States may indicate that the permit remains valid *as long as the well is producing*. Under that circumstance, a permit can be revoked by states for the following reasons:
    a. Failure to comply with environmental standards
    b. Unsafe drilling practices
    c. Non-payment of fees or failure to submit required reports
    d. Failure to properly plug wells after they become non-productive
    e. Failure to meet requirements for well closure, plugging, and site reclamation

1.9 Reporting Requirements

1. The following can be considered for reporting in a Development Permit:
    a. Notice of Change
        1) Change to information submitted with the application, including disturbance area, well count, well drilling, planned equipment, disposal practices, and production operations
    a. Notice of Construction
        1) The permit may specify the number of days for notice to the agency in advance of mobilizing heavy equipment to construct a permitted location.
    b. Notice of Well Drilling
        1) The permit may specify the number of days for notice to the agency in advance of well drilling.
    c. Spill Notification
        1) In accordance with requirements in rules administered by PCA
    d. Operations Report
        1) Frequency and required information would be determined by the permitting agency, which could include monthly or semi-annual reporting for the volume of produced gas and any fluids.

2) The permitting agency can require metering equipment identified through industry standards established by the American Petroleum Institute (API), with required annual calibration.

3) Should they be determined necessary for a Development Permit, Colorado provides examples at Rule 405 of additional operations requiring individual notice.

e. Notice of Shut-in, Temporarily Abandoned, Abandoned Well

1) A well may be shut in after drilling and testing for a period that provides for installation of production equipment.

2) A well may be temporarily abandoned for a period that provides for future use, such as completion or deepening.

3) A well may be plugged and abandoned if testing does not demonstrate economical volumes of helium gas.

f. In Utah at Rule 649-3-39.3.3.4 (in the context of hydraulic fracturing), operators must also file an Annual Waste Management Plan to report the proper disposition of produced water and other exploration and production (E&P) waste.

Colorado Energy & Carbon Management Commission, Rule 405
https://ecmc.state.co.us/documents/reg/Rules/LATEST/400%20Series%20-%20Operations%20and%20Reporting.pdf

Utah Division of Oil, Gas and Mining, Rule 649-3
https://adminrules.utah.gov/public/rule/R649-3/Current%20Rules?searchText=R649

Siting

1.10 Siting Restrictions

1. Disturbance for an oil and gas operation is generally prohibited in habitats for species designated endangered, threatened, or special status.

   a. Exceptions may be granted for access roads and flowlines in the buffer areas for certain aquatic habitats, as they are in Colorado under Rule 1202.c.(2).C.

2. Protection for avian species can include a requirement to conduct vegetation removal outside of the nesting season for migratory birds or, alternatively, to conduct a pre-construction survey for nesting migratory birds. An example is at Colorado Rule 1202.a.(8).

Colorado Energy & Carbon Management Commission, Rule 1202
https://ecmc.state.co.us/documents/reg/Rules/LATEST/1200%20Series%20-%20Protection%20of%20Wildlife%20Resources.pdf

1.11 Setbacks

1. Setbacks from a residential building vary by state with examples of the required distance listed below.

   a. Residential can include schools, childcare centers, offices, and hospitals, according to individual state requirements.

   b. Residential generally does not include garages, barns, and outbuildings.

   c. States vary in measuring from the well or measuring from the edge of the well pad.

Residential Setbacks	
State	**Setback (feet)**
Colorado	2,000
Montana	1,320
North Dakota	500
Wyoming	500
Utah	460
Michigan	300
Pennsylvania	200

2. Setbacks from roadways are identified by certain states. Examples are listed below.
    a. The measurement and application of the setback affects its restrictiveness. These vary from the edge of the road to the edge of the traveled portion of an interstate or state highway, to the centerline of an interstate or state highway.

Roadway Setbacks	
State	**Setback (feet)**
Michigan	300
Colorado	200
North Dakota	200

    b. In addition to roadways, setbacks are applied in certain states to aboveground utilities and railroads.
3. Setbacks from water wells are identified by certain states. Examples are listed below.

Water Well Setbacks	
State	**Setback (feet)**
Colorado	2,640
Kansas	660
Michigan	300
Pennsylvania	200

4. A process generally exists to grant a waiver or variance after site-specific evaluation by the regulatory agency or a consulting agency.
    a. Proximity to a residence may consider, for example, the consent of the affected property owner.
    b. Habitat review may consider habitat type, suitability, use as habitat, and existing integrity.
    c. Surface water review may consider site survey for mapped waters and wetlands, erosion potential, spill controls, topography, and floodplains.
5. Measures to avoid, minimize, or mitigate impacts can be incorporated into a permit as Conditions of Approval or Best Management Practices.

Colorado Energy & Carbon Management Commission, Rule 304.b.(2).B
https://ecmc.state.co.us/documents/reg/Rules/LATEST/300%20Series%20-%20Permitting%20Process.pdf

Colorado Energy & Carbon Management Commission, Rule 604
https://ecmc.state.co.us/documents/reg/Rules/LATEST/600%20Series%20-%20Safety%20and%20Facility%20Operations%20Regulations.pdf

*Colorado Energy & Carbon Management Commission, Rule 1202.*a
https://ecmc.state.co.us/documents/reg/Rules/LATEST/1200%20Series%20-%20Protection%20of%20Wildlife%20Resources.pdf

Kansas Corporation Commission, Rule 82-3-108.(a)
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

Michigan Department of Environmental Quality, Rule 324.201.2.b.iv.A, Rule 324.504
https://dtmb.state.mi.us/ORRDocs/AdminCode/1889_2019-001EQ_AdminCode.pdf#:~:text=These%20rules%20govern%20oil%20and%20gas

Montana Board of Oil and Gas Conservation, Rule 36.25
https://casetext.com/regulation/montana-administrative-code/department-36-natural-resources-and-conservation/chapter-3625-state-land-leasing/subchapter-36252-rules-governing-the-issuance-of-oil-and-gas-leases-on-state-lands/rule-3625223-minimum-restrictions-on-surface-activity

North Dakota Department of Mineral Resources, Rule 38-08-05.2
https://ndlegis.gov/cencode/t38c08.pdf, https://www.dmr.nd.gov/oilgas/DMR-drill-101_106.pdf

Pennsylvania Code, Section 3215.0 Title 58
https://www.legis.state.pa.us/WU01/LI/LI/CT/HTM/58/00.032.015.000..HTM#:~:text=%281%29%20No%20well%20site%20may%20be%20prepared%20or,quadrangle%20map%20of%20the%20United%20States%20Geological%20Survey.

Wyoming Oil and Gas Conservation Commission Rule 055.0001.3, Section 47.(a)
https://rules.wyo.gov/Search.aspx#

1.12 Surface Use Agreement

1. The requirements listed below can be considered for inclusion in a Surface Use Agreement (SUA) between the operator and the surface owner.
   a. If an operator is not relying on a lease for its right to construct, the requirements can be included in the Development Permit.
2. Requirements:
   a. Clearly provide a “Right to Construct.”
   b. Include a legal description of the lands subject to the agreement.
   c. Clearly state that it applies to gas or helium operations.
   d. Include signatures for the operator and surface owner.
   e. Include language on successors and assigns if a successor operator is using the SUA for siting.

Leasing

1.13 Examples for State Mineral Leases

1. The recommended practice for helium is for the state to lease helium consistent with a state leasing process for oil and natural gas. This approach is used in Colorado and Wyoming.

See Section 4.e., Definition of "Gas", in Colorado Oil and Gas Lease Sample, https://drive.google.com/file/d/1w2BvfCyTxPvEXHa9veZm9j6NYFeDnl80/view

2. For comparison, Utah uses a non-solicited "Other Business Arrangement" (OBA) (*see* No. 11 below) or other non-lease process.
3. Colorado and Wyoming appear to use a 16.67 percent royalty rate in their respective oil and gas leases.
4. A 16.67 percent royalty rate is consistent with the Bureau of Land Management (BLM) royalty rate for leases issued between 2022 and 2032 at 43 C.F.R. § 3103.31(a)(2).
5. Colorado oil and gas lease samples are viewable here:

   https://drive.google.com/file/d/1w2BvfCyTxPvEXHa9veZm9j6NYFeDnl80/view

   https://ecmc.state.co.us/weblink/DownloadDocumentPDF.aspx?DocumentId=3097274
6. A Wyoming oil and gas lease form is viewable here:

   https://drive.google.com/file/d/1wNbWGPaaASDVzQt-zYVdegAKDP6eZ_xA/view
7. A BLM oil and gas lease (Form 3100-11) is viewable here:

   https://www.blm.gov/sites/blm.gov/files/uploads/Services_National-Operations-Center_Eforms_Fluid-and-Solid-Minerals_3100-011.pdf
8. A BLM Competitive Oil and Gas or Geothermal Resources Lease Bid (Form 3000-002) is viewable here:

   https://www.blm.gov/sites/default/files/docs/2024-05/3000-002.pdf
9. Colorado Lease Process:
   a. Colorado's State Land Board offers oil and gas leases through competitive auctions.
   b. Auctions occur online.
   c. Anyone can nominate state minerals for auction to obtain a lease.
   d. Leases are awarded to the highest bidder on a per acre basis.
   e. The minimum bid amount per acre is the annual lease rental rate.

   Colorado State Land Board Oil & Gas Auction and Results https://slb.colorado.gov/public-notices/auction-results
10. Wyoming Lease Process:
    a. Oil and gas leases can be acquired through two methods.
       1) First, parcels that are available for lease are auctioned through a competitive bid process. If a parcel is not successfully bid upon, the parcel may be offered at a second auction.
       2) Second, if a parcel is not successfully bid upon a second time, the parcel may become available "over the counter" at set prices.

    Wyoming Oil & Gas Leases: https://lands.wyo.gov/trust-land-management/mineral-leasing/oil-gas-leases

11. Utah Lease Process:
    a. Utah follows a different process than Colorado and Wyoming.
    b. In Utah, helium is “leased” via OBA.
    c. OBA’s are customized agreements with Utah’s School and Institutional Trust Lands Administration (SITLA), which requires the project proponent to use geographic information system (GIS) maps to ensure that the interested lands are not already subject to an existing lease.
    d. The project proponent must reach out to the SITLA Energy & Minerals group to submit a letter of interest explaining the nature of the transaction (e.g., royalty rate, plan of development, etc.).
    e. The Energy & Minerals group lease managers then reach out to begin negotiation.
    f. The OBA is approved by the SITLA Board of Trustees.

    Utah SITLA Other Business Arrangements: https://trustlands.utah.gov/work-with-us/energy-minerals/oba/

Spacing / Unitization

1.14 Technically Supported Drilling Spacing Unit

1. The area of development for a Drilling Spacing Unit (DSU) can be supported using engineering testimony demonstrating one or more of the following:
    a. Fluid reservoir properties including, as appropriate, fluid types, API gravity, specific gravity, gas/oil ratio, formation volume factor, porosity, pore space saturation and permeability
    b. Evaluation of analog wells in the nearby area, if available
    c. Table of reservoir engineering calculations for original gas-in-place, estimated ultimate recovery (EUR), and the calculated drainage area for each well
    d. Decline curve(s) and how the analysis was used to calculate EURs for use in the drainage area calculations
    e. Reservoir data, including pressure surveys, material balance calculations, and other reservoir information that supports the size and continuity of the reservoir, or the productivity of the reservoir(s)
    f. Seismic survey maps, if available, interpreting section lines and synthetic seismic logs
    g. Microseismic data, if available, with an indication of the confidence interval, signal to noise ratio, and/or magnitude of microseismic events
2. The presence of the formation within the defined DSU can be supported using geology testimony demonstrating one or more of the following:
    a. Summary of the formation(s) to be spaced including the name, description, lithology, characteristics, depositional origin and, if applicable, faults, folds, stratigraphy variation, and trap type
    b. Description of the thickness, lateral extent, and depth of the formation(s) to be spaced
    c. Structure contour map showing the top subsea elevation of the formation(s) to be spaced
    d. Isopach map showing gross or net thickness of the formation(s) to be spaced

e. Cross-section showing the geology of the formation(s) to be spaced

f. Type log showing the geology of the formation(s) to be spaced

1.15 Protect Correlative Rights / Prevent Waste

1. Correlative rights can be defined in statute.

   a. In Colorado, Colorado Revised Statute (C.R.S.) § 34-60-103(6)(a) defines correlative rights as “each owner and producer in a common pool or source of supply of oil and gas must have an equal opportunity to obtain and produce the owner’s or producer’s just and equitable share of the oil and gas underlying the pool or source of supply.”

   b. Colorado statute at C.R.S. § 34-60-117 prohibits harm to correlative rights.

   c. Colorado statute and ECMC rules require ECMC to protect correlative rights.

   d. The evaluation of new spacing in Minnesota can similarly include the requirement to protect correlative rights.

2. Preventing waste can be defined in statute.

   a. In Colorado, C.R.S. 34-60-103(43), (44) and (45) define waste as it applies to oil, gas, and generally, including:

      1) Physical waste, as that term is generally understood in the oil and gas industry;

      2) The locating, spacing, drilling, equipping, operating, or producing of any oil or gas well or wells in a manner that causes or tends to cause reduction in quantity of oil or gas ultimately recoverable from a pool under prudent and proper operations or that causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas;

      3) Abuse of the correlative rights of any owner in a pool due to nonuniform, disproportionate, unratable, or excessive withdrawals of oil or gas from the pool, causing reasonably avoidable drainage between tracts of land or resulting in one or more producers or owners in the pool producing more than an equitable share of the oil or gas from the pool; and

      4) Does not include the nonproduction of oil or gas from a formation if necessary to protect public health, safety, and welfare; the environment; or wildlife resources.

   b. In Colorado, ECMC also has a duty at C.R.S. § 34-60-117 to prevent waste.

   c. The evaluation of new spacing in Minnesota can similarly include the requirement to prevent waste.

Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

1.16 Threshold Leasehold Ownership to Obtain a DSU

1. An operator seeking to establish a DSU for a proposed development area should own or have the consent to operate within the proposed unit.

   a. In Colorado, “Owner” means “the person who has the right to drill into and produce from a pool and to appropriate the oil or gas produced therefrom either for such owner or others or for such owner and others, including owners of a well capable of producing oil or gas, or both."

2. Evidence of mineral ownership or consent to develop would be included as a requirement in the spacing application.
3. In Colorado, an operator cannot pool interests within an established DSU without first owning and/or obtaining the consent of the owners of more than 45 percent of the mineral interests to be pooled.
4. While Colorado does not require 45.1 percent ownership or consent at the time of spacing, the ECMC considers this threshold as it relates to future pooling.
5. Colorado recently enacted a new law at C.R.S. § 34-60-116 that requires a pooling applicant to submit to the ECMC an affidavit with a lease schedule, including recording information and wells holding each lease by production, to demonstrate that the operator owns at least 45.1 percent of the leasehold interests to be pooled.
6. Wyoming has no pooling ownership threshold. In Wyoming, the operator has the right to drill and develop within the defined lands.

   Colorado Energy & Carbon Management Commission, Rule 100
   https://ecmc.state.co.us/documents/reg/Rules/LATEST/100%20Series%20-%20Definitions.pdf

   Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
   https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

Pooling

1.17 General

1. Most states with oil and gas reserves have enacted statutory pooling laws to encourage development of the resource and participation by mineral owners.
2. In Colorado and Wyoming, pooling may be done voluntarily between parties.
   a. Voluntary pooling may be done through contracts, in which state entities will have little to no involvement.
3. Involuntary pooling may be done by an operator if the operator fulfills certain statutory requirements.
4. In Colorado, a pooling order does not expire.
5. In Wyoming Statute at 30-5-109.(f), a pooling order will expire (become non-effective) 12 months after the Oil & Gas Conservation Commission approves the order if the well is not drilled within the 12 months following order approval.

   Wyoming Statute, Title 30, Chapter 5, Oil and Gas
   https://wyoleg.gov/statutes/compress/title30.pdf

1.18 Identification of Mineral Owners

1. An operator can apply for pooling with the spacing of a DSU or after the DSU has been established.
   a. The DSU should at least be established before minerals are pooled within the unit.

2. Prior to applying for pooling, an operator should identify the unleased mineral owners; leasehold (working interest) owners; and leased royalty owners within the unit.

3. Also prior to applying for pooling, requirements for tendering lease offers and elections to participate can be imposed.

Colorado Energy & Carbon Management Commission, Rule 506
https://ecmc.state.co.us/documents/reg/Rules/LATEST/500%20Series%20-%20Rules%20of%20Practice%20and%20Procedure.pdf

1.19 Notification of Mineral Owners

1. Notification to unleased mineral owners, leasehold (working interest) owners, and leased royalty owners would occur when an operator applies for pooling.

2. Recent revision to the statute in Colorado regarding pooling at C.R.S. § 34-60-116 requires a 60-day protest/petition period by unleased mineral owners prior to a hearing on a pooling application.

   Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
   https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

1.20 100 Percent Mineral Leasing Versus Statutory Pooling

1. Statutory (involuntary) pooling may not be required when 100 percent of the minerals within an established DSU are owned and/or leased to the operator.

2. No further state action is needed with respect to pooling when an operator is developing its 100 percent leasehold interests or if involuntary pooling is obtained.

3. At the time of filing for a Development Permit, the operator should state whether the minerals being developed are owned and/or leased 100 percent to the operator, or whether pooling is required.

1.21 Joint Operating Agreement

1. Participating mineral owners can execute a Joint Operating Agreement (JOA) with the operator, which provides the contractual basis for the cooperative exploration, development, and production of oil and gas properties among multiple leasehold cotenants.

2. The most commonly used JOA form is the "Form 610," curated and published by the American Association of Professional Landmen.

3. Because the JOA is a contract between the operator and the participating leasehold owners, the state may be aware of the presence of a JOA but otherwise will not have regulatory authority over the JOA.

1.22 Nonconsent Working Interest / Unleased Mineral Owner

1. Statutory pooling may provide that the operator and consenting owners recover costs in the form of cost recovery penalties out of the nonconsenting owners' share of production from a DSU.

2. After an operator (a) tenders (mails to a last known address) an election to participate in the proposed well(s), which is sent to the leasehold (working interest) and unleased owners within the unit, and (b) these mineral owners have a reasonable time to consider the election materials, then an operator may seek cost recovery penalties against a mineral owner that either 1) fails to respond to the election materials or 2) responds with an election not to participate.

   a. In Colorado, the reasonable time to consider the election materials is 60 days.

3. Colorado cost recovery penalties at C.R.S. § 34-60-116 are:

    a. 100 percent of the nonconsenting owners' share of the cost of surface equipment beyond the wellhead connections.

    b. 200 percent of that portion of the costs and expenses of staking, well site preparation, obtaining rights-of-way, rigging up, drilling, reworking, deepening or plugging back, testing, and completing the well, after deducting any cash contributions received by the consenting owners, and 200 percent of that portion of the cost of equipment in the well, including the wellhead connections.

4. Wyoming cost recovery penalties at Wyoming Statute 30-5-109 are:

    a. 100 percent of the nonconsenting owner's share of the cost of any newly acquired surface equipment (applies to all nonconsenting owners).

    b. 300 percent of that portion of costs and expenses drilling and reworking. 200 percent of that portion of costs of newly acquired equipment in the well, "if the nonconsenting owner's tract or interest is subject to a lease or other contract of oil and gas development" (applies only to nonconsenting owners who hold a lease).

    c. For the first well, 200 percent of that portion of costs and expenses of drilling and reworking. 125 percent of that portion of costs of newly acquired equipment in the well "if the nonconsenting owner's tract or interest is not subject to a lease or other contract for oil and gas development" (applies to unleased mineral owners).

    d. For each subsequent well, 150 percent of that portion of costs and expenses of drilling, reworking, etc. 125 percent of that portion of costs of newly acquired equipment in the well, "if the nonconsenting owner's tract or interest is not subject to a lease or other contract for oil and gas development" (applies to unleased mineral owners).

Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

Wyoming Statute, Title 30, Chapter 5, Oil and Gas
https://wyoleg.gov/statutes/compress/title30.pdf

1.23 Unleased Mineral Owner Royalty Cost Recovery

1. If an unleased owner refuses or does not respond to a lease offer, the unleased owner may be deemed to have a landowner's proportionate royalty.

2. After an operator tenders a reasonable lease offer to all unleased owners in the unit, and these unleased owners have a reasonable time to consider the lease offer, then an operator may seek cost recovery penalties in the form of statutory royalty against an unleased mineral owner that either 1) fails to respond to the lease offer or 2) responds with an explicit rejection of the lease offer.

    a. A reasonable lease offer is based on market rates.

    b. In Colorado, the reasonable time to consider the lease offer is 60 days.

3. Colorado statutory royalty at C.R.S. § 34-60-116 is:

    a. For a gas well, 13 percent until the consenting owners recover, only out of the nonconsenting owner's proportionate 87 percent share of production, the costs specified in the statute; or

b. For an oil well, 16 percent until the consenting owners recover, only out of the nonconsenting owner's proportionate 84 percent share of production, the costs specified in the statute.

c. After recovery of the costs, the nonconsenting owner then owns his or her full proportionate share of the wells, surface facilities, and production and then is liable for further costs as if the nonconsenting owner had originally agreed to drilling of the wells.

4. Wyoming statutory royalty at Wyoming Statute 30-5-109 is:

   d. 16 percent, or the acreage weighted average royalty interest of the leased tracts within the drilling unit.

Colorado Energy & Carbon Management Commission, Rule 506
https://ecmc.state.co.us/documents/reg/Rules/LATEST/500%20Series%20-%20Rules%20of%20Practice%20and%20Procedure.pdf

Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

Wyoming Statute, Title 30, Chapter 5, Oil and Gas
https://wyoleg.gov/statutes/compress/title30.pdf

1.24 Royalty Cost Recovery Reporting

1. Colorado requires that the operator of wells under a pooling order in which there is a nonconsenting owner furnish the nonconsenting owner with a monthly statement of all costs incurred, together with the quantity of oil or gas produced, and the amount of proceeds realized from the sale of production during the preceding month.
2. If the consenting owners recover the costs specified in statute, the nonconsenting owner will own the same interest in the wells, and the production therefrom, and will be liable for the further costs of the operation, as if the owner had participated in the initial drilling operations.

Colorado Energy & Carbon Management Commission, Rule 506
https://ecmc.state.co.us/documents/reg/Rules/LATEST/500%20Series%20-%20Rules%20of%20Practice%20and%20Procedure.pdf

Colorado Revised Statute, Title 34, Article 60, Energy and Carbon Management
https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=5d45e50e-a97a-4d50-8564-5829d9c816b0&prid=e49f6bad-fe66-499f-9d93-5b4d2f62d7fa

Reclamation

1.25 Interim Reclamation

1. Interim reclamation refers to reducing the well pad after drilling is complete to the size needed to support production. The remaining area would be required to be reclaimed by restoring and revegetating the disturbed surface.
2. States vary from specific reclamation requirements in Colorado at Rule 1003 for debris removal, soil salvage, vegetative cover, and weed control to a general requirement in Kansas at Rule 55-182 to restore the area to original contour and condition as nearly as practicable. Likewise, Montana at Rule 36.22.1307 has only a general requirement to restore the surface to its previous grade and productive capability.

3. A timeframe can be specified to conduct interim reclamation.
    a. In Colorado at Rule 1003.b, the timeframe is 3 months after well drilling is complete for cropland and 6 months for non-cropland.
4. Additional practices below can be specified to facilitate successful reclamation and revegetation.
    a. Disturbance for the well pad would be limited to the area necessary to place and level equipment for well drilling and production.
    b. Equipment not needed to support production would be removed after well drilling.
    c. Debris and trash would be removed from the site.
    d. Topsoil stripped during construction of the well pad would be stockpiled and replaced during reclamation.
    e. The topsoil stockpile would be protected from parking and contamination during well drilling and production.
    f. The topsoil stockpile would be protected from stormwater erosion and runoff through stormwater controls and vegetative cover.
    g. Reclaimed areas would be seeded with a certified weed-free seed mix that is consistent with native vegetation.
    h. The operator would continue to manage the location for stormwater runoff and weeds until the area is stabilized according to provisions in its construction stormwater permit.

Colorado Energy & Carbon Management Commission, Rule 1003
https://ecmc.state.co.us/documents/reg/Rules/LATEST/1000%20Series%20-%20Reclamation%20Regulations.pdf

Kansas Corporation Commission, Rule 55-182
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

Montana Board of Oil and Gas Conservation, Rule 36.22.1307
https://rules.mt.gov/browse/collections/aec52c46-128e-4279-9068-8af5d5432d74/policies/6c4248a4-a1b8-48aa-99f4-68bb1d024081

1.26 Final Reclamation

1. Final reclamation refers to restoration of the site after the well is plugged and abandoned and the site no longer supports production. The surface, including the access road, would be returned to a pre-existing condition.
    a. In some cases, the landowner may specify in its agreement with the operator that an access road remain in place for the landowner's own use.
2. Final reclamation requirements are designed to return the surface to a stable and productive condition for future use without environmental risks.
3. States vary from specific reclamation requirements in Colorado at Rule 1004 for final closure, recontouring and revegetation, inspection, and bond release to more general requirements in Wyoming at Rule 055.0001.4.rr for site rehabilitation in accordance with reasonable landowner wishes and/or to resemble the original vegetation and contour of adjoining lands.
4. A timeframe can be specified to conduct final reclamation.

   a. In Colorado at Rule 1004.a, the timeframe is 3 months after well plugging or site closure for cropland and 12 months for non-cropland.

   b. In North Dakota at Rule 43-02-03-34.1, the timeframe is 12 months after well plugging or site decommissioning.

5. Additional practices below can be specified to facilitate final closure.

   a. Submitting a Reclamation Plan is required in certain states, such as Colorado and North Dakota.

   b. Risers, flowlines at the location, culverts, equipment, debris, trash, and surfacing material (e.g., gravel) would be removed.

   c. The site and access road would be de-compacted, recontoured, and graded.

   d. Stormwater control materials would be removed.

   e. Hydrological flow patterns for stormwater would be restored.

   f. Topsoil preserved for final reclamation would be restored.

   g. Reclaimed areas would be seeded with a certified weed-free seed mix that is consistent with native vegetation.

   h. The operator would continue to monitor the site and reseed, as necessary, until revegetation stabilizes exposed soils.

   i. Bonding would be held until final reclamation is inspected and found complete.

Colorado Energy & Carbon Management Commission, Rule 1004
https://ecmc.state.co.us/documents/reg/Rules/LATEST/1000%20Series%20-%20Reclamation%20Regulations.pdf

North Dakota Department of Mineral Resources Rule 42-02-03-34.1
https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.4, Section 1.(rr)
https://rules.wyo.gov/Search.aspx?mode=1

Site Closure

1.27 Site Closure Requirements

1. Site closure refers to abandonment of the location not otherwise addressed by well plugging.

2. Equipment, infrastructure, trash, and debris would be removed from the site.

3. Waste from drilling and production would require proper final disposal in an approved landfill, disposal facility, or as otherwise indicated in the operator’s permit.

4. Associated flowlines would be purged and permanently sealed or removed.

5. In Colorado at Rule 603.m, the operator must initiate closure of the well site within 90 days after a well is plugged and abandoned.

   a. In North Dakota, the timeframe increases to 1 year.

   b. North Dakota requires that any flowline buried less than 3 feet below the final surface be removed rather than abandoned in place.

Colorado Energy & Carbon Management Commission, Rule 603

https://ecmc.state.co.us/documents/reg/Rules/LATEST/600%20Series%20-%20Safety%20and%20Facility%20Operations%20Regulations.pdf

North Dakota Department of Mineral Resources, Rule 43-02-03-34.1
https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf

Financial Assurance

1.28 Application Fee

1. Example fees by state are listed below.

Application Fee	
Illinois	$400
Kansas	$300
Michigan	$300
Montana	$25 - $75
North Dakota	$100
Wyoming	$500
U.S. Bureau of Land Management	$12,515[1]

[1]Onshore O&G Operations and Production, Application for Permit to Drill

Illinois Department of Natural Resources
https://dnr.illinois.gov/oilandgas/formslistslogs.html

Kansas Corporation Commission, Rule 55-151.b
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

Montana Board of Oil and Gas Conservation, Rule 36.22.603
https://casetext.com/regulation/montana-administrative-code/department-36-natural-resources-and-conservation/chapter-3622-oil-and-gas-conservation/subchapter-36226-permit-to-drill/rule-3622603-permit-fees?searchWithin=true&listingIndexId=montana-administrative-code.department-36-natural-resources-and-conservation.chapter-3622-oil-and-gas-conservation.subchapter-36226-permit-to-drill&q=water%20well&type=regulation&sort=relevance&p=1

North Dakota Department of Environmental Quality, Rule 43-02-03-16
https://ndlegis.gov/information/acdata/pdf/43-02-03.pdf
https://deq.nd.gov/AQ/oilgas/OilGasRegistration.aspx

Wyoming Oil and Gas Conservation Commission, Rule 055.0001.3, Section 8
https://rules.wyo.gov/Search.aspx

U.S. Bureau of Land Management Fixed Filing Fees
https://www.blm.gov/fixed-filing-fee-schedule-blm-energy-and-minerals

1.29 Application Review Fee

1. Examples of agencies that charge an hourly fee for oil and gas-related application review for permits in their jurisdiction are listed below.

Application Review Fee	
Garfield County, Colorado	Staff or Consultant Hourly Rate
Wyoming Department of Environmental Quality	Staff Hourly Rate
U.S. Bureau of Land Management	Escalating Rate by Category and Hours

Application Review Fee	
U.S. Forest Service	Escalating Rate by Complexity and Hours

2. The federal agencies listed above are granted authority to charge fees for processing applications related to land use and minerals.
3. Agencies bill the applicant for the time necessary to review and process the application.
4. A mechanism is in place to adjust fees annually for inflation.

   Garfield County, Colorado Planning Review Process Fee Schedule
   https://www.garfield-county.com/community-development/filesgcco/sites/12/2019/01/Fee-Schedule.pdf

   U.S. Bureau of Land Management Cost Recovery Process and Monitoring Fee Schedule
   https://www.blm.gov/sites/default/files/docs/2023-12/IM2024-008%20att1.pdf

   U.S. Forest Service Code of Federal Regulations Title 36, Chapter II, Section 251.58
   https://www.ecfr.gov/current/title-36/chapter-II/part-251/subpart-B/section-251.58

   Wyoming Department of Environmental Quality Oil and Gas Production Facilities Chapter 6, Section 2
   https://drive.google.com/file/d/1IbN-U0sDMDsYjhaPwwf1GnFX1avKsIdv/view

1.30 Annual Fee

1. Publicly available annual fees appear limited to fees in the range of $100 per operator and either a fee per well (e.g., $25/well) or escalating fee by volume of wells (e.g., $150 to $750+ per category).
2. There were no fees identified that would be comparable in scale to the annual fees imposed for mining operations in Minnesota Statute 93.482.

1.31 Plugging, Reclamation, Surface Bonding

1. In Colorado, financial assurance is required for all operators of drilled wells and unexpired permits.
   a. Operators must have financial assurance with the ECMC, even when the operator also has financial assurance with a federal agency, such as the BLM.
   b. Bonding is treated differently at ECMC Rule 703 for wells than it is for the following categories of operations: centralized exploration and production waste facilities, remediation projects, seismic operations, gas gathering, gas processing, underground gas storage facilities, produced water transfer systems, and commercial disposal facilities.
2. Financial assurance may be a surety bond, cash bond, letter of credit, sinking fund, third-party trust fund, escrow account, lien on property, security interest, or other instrument or method accepted by ECMC to ensure an operator is able to perform its obligations under the Colorado Oil and Gas Act and ECMC rules.
3. Financial assurance requirements for oil and gas operators are generally more detailed in Colorado than in other oil and gas states and are summarized below.
   a. Colorado operators of one or more producing or actively permitted wells must have an approved Financial Assurance Plan filed with the ECMC.
   b. Colorado operators must have bonding based primarily on production volumes.

c. Options 1, 2, 3 and 6 Financial Assurance Plans require the calculation of average daily production per well in thousand cubic feet of gas equivalent (MCFE).

d. At Colorado Rules 702.c and 702.d, bonding ranges from single well financial assurance, to per well calculations based on classification for the number of wells operated, to a $40,000,000 blanket bond for public companies with high production rates.

e. At Colorado Rule 100, single well financial assurance is defined using an estimate of $100,000 to reclaim the surface location and $10,000 to plug a well that is 4,000 feet deep, or less, and $30,000 to plug a well that is more than 4,000 feet deep and equal to or less than 8,000 feet deep.

f. Options 4 and 5 Financial Assurance Plans are for operators reporting zero production or for individual circumstances that require ECMC Commissioners to approve alternative bonding amounts.

4. Each Financial Assurance Plan in Colorado must contain an Asset Retirement Plan.

5. In Colorado at Rule 704, if a surface owner is not a party to a lease, surface use agreement, or other relevant agreement with an operator, the operator must provide financial assurance to the ECMC before commencing operations with heavy equipment on that surface owner's property.

6. Colorado at Rule 705 requires general liability insurance in the minimum amount of $5,000,000 per occurrence.

7. Colorado at Rule 706 will not release financial assurance until the well is properly plugged and abandoned and the location is fully reclaimed.

8. For comparison, in Wyoming bonding is based on the number of wells, well depth, and the type of minerals involved.

   a. Fee minerals in Wyoming are bonded with the Wyoming Oil & Gas Commission.

   b. State minerals are bonded with the Office of Public Lands and Investments.

   c. Federal minerals are bonded with the BLM in the county where the well is located.

9. Oil and gas bonding requirements in Wyoming include the following:

   a. Individual well bonds are $10 per foot of the well bore and are adjusted every 3 years.

   b. Blanket bonds are $100,000 for multiple wells, regardless of well depth.

   c. Idle wells may be subject to an increase in the bond amount of up to $10 per foot of the well bore.

Colorado Energy & Carbon Management Commission 100-Series Definitions
https://ecmc.state.co.us/documents/reg/Rules/LATEST/100%20Series%20-%20Definitions.pdf

Colorado Energy & Carbon Management Commission 700-Series Rules
https://ecmc.state.co.us/documents/reg/Rules/LATEST/700%20Series%20-20Financial%20Assurance.pdf.

Wyoming Oil and Gas Conservation Commission, Chapter 3, Section 4 Bonding Requirements
https://rules.wyo.gov/Search.aspx?mode=7

Glossary of Terms

1.32 Oil & Gas Sector Terminology

Terms commonly used in the oil and gas sector are shown in the table below. Some of the terms contrast with terms applied to mining operations or water wells in Minnesota.

Terms	
Terms in Current Use in Minnesota	**Oil and Gas Sector**
Project	Operation
Explorer	Operator
Well contractor	Driller
Drill site	Well pad
Exploratory boring	Exploration well
Extraction	Production
Sealing	Plugging
Grouting	Cementing
Aboveground storage tank	Produced water tank
Driveway	Access road
Industrial waste	Exploration & Production (E&P) waste
Piping	Flowline or pipeline

2.0 Minnesota Department of Revenue

Taxation

2.1 Precedent for Helium-specific Tax Rate

1. Severance taxes are taxes set and collected at the state level for extraction of natural resources, such as oil and natural gas.
2. Severance taxes for oil and gas are typically calculated based on the value and/or volume produced.
3. Best practice for a severance tax applicable to helium is to ensure that the statute or regulations implementing the severance tax are clear on its application to helium gas and to provide clear direction on calculation of the proceeds subject to the severance tax.
4. Colorado example:
   a. Colorado has a severance tax on (1) metallic minerals (2) molybdenum (ore) (3) oil and gas (4) oil shale and (5) coal. *See* C.R.S. § 39-29-103 through 107.
   b. Colorado does not have a severance tax specific to helium. Instead, "gas" means natural gas, coalbed methane, and CO2. *See* C.R.S. § 39-29-102(2.5).
   c. For each taxable year, a tax on the gross income attributable to the sale of crude oil, natural gas, CO2, and oil and gas is collected at the following rates [*See* C.R.S. § 39-29-105(1)(a)]:

Gross Income	Severance Tax
Under $25,000	2%
$25,000 and under $100,000	3%
$100,000 and under $300,000	4%
$300,000 and over	5%

   d. "Gross Income" is calculated by deducting from gross lease revenues any costs borne by the taxpayer for transporting, manufacturing, and processing identifiable, measurable oil or gas. *See* 1 CCR 201-10 and C.R.S. § 39-29-102(3)(a).
5. New Mexico example:
   a. New Mexico has a severance tax on oil, natural gas, liquid hydrocarbons, CO2, helium, and non-hydrocarbon gases. *See* New Mexico Stat. Ann. § 7-29-4(A).
   b. For CO2, helium, and non-hydrocarbon gases, the severance tax is 3.75 percent of the taxable value.
   c. To determine the taxable value of helium, the following is deducted from the value of products: (1) royalties paid or due the United States or the state of New Mexico (2) royalties paid or due any Indian tribe, Indian pueblo or Indian that is a ward of the U.S. and (3) the reasonable expense of trucking any product from the production unit to the first place of market. *See* New Mexico Stat. Ann. § 7-29-4.1.

6. Wyoming example:

   a. Wyoming has a severance tax on coal, oil and gas, bentonite, uranium, sand and gravel, and other valuable deposits. *See* 39 Wyo. Stat. Ann. § 39-14-101 through 701.

   b. Helium is subject to the severance tax rate for natural gas, which is 6 percent on the value of gross product of helium. *See* 39 Wyo. Stat. Ann. § 39-14-204(a), 212(f), 203(a)(i).

   c. The "value of the gross product" means fair market value, less any deductions and exemption allowed by Wyoming law or rules. *See* 39 Wyo. Stat. Ann. § 39-14-201(a)(xxix).

   d. The fair market value of natural gas is determined after the production process is completed. *See* 39 Wyo. Stat. Ann. § 39-14-203(b)(ii).

   e. Helium from a natural gas stream leased by the U.S. to any lessee pursuant to the Mineral Leasing Act of 1920 is exempt from this severance tax. *See* 39 Wyo. Stat. Ann. § 39-14-212(g).

Colorado Code of Regulations, 1 CCR 201-10, Severance Tax
https://www.sos.state.co.us/CCR/KeywordSearch.do?id=&submit=Search&keyword=201&d-49216-p=2&endDate=&startDate=

Colorado Revised Statute, Title 39, Article 29, Severance Tax
https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=fc0ae068-f0d2-48ce-a877-f8f48c94a079&prid=5d45e50e-a97a-4d50-8564-5829d9c816b0

New Mexico Statutes Annotated, Article 29, Title 7, Oil and Gas Severance Tax
https://nmonesource.com/nmos/nmsa/en/item/4340/index.do#!fragment/zoupio-_Toc170909147/BQCwhgziBcwMYgK4DsDWszIQewE4BUBTADwBdoAvbRABwEtsBaAfX2zgEYB2ABgE5+HACxcAIABpk2UoQgBFRIVwBPaAHI14iITC4ECpao1adekAGU8pAEKqASgFEAMg4BqAQQByAYQfjSYABG0KTsoqJAA

Wyoming Statute, Title 39, Chapter 14, Taxation and Revenue
https://wyoleg.gov/statutes/compress/title39.pdf

2.2 Helium Gas Versus Liquid Helium Pricing

1. Helium pricing increases as raw gas is separated to produce crude helium gas (e.g., >90% to 98% crude helium) and then purified further as liquid helium (e.g., 99.997% Grade A market premium helium).

2. In its purified state, liquid helium may be converted back to gaseous form depending on the end user's requirements, such as use in semiconductor manufacturing.

3. The initial raw gas may contain helium together with hydrocarbons, CO2, nitrogen, and other constituents.

4. When raw gas is separated, helium can be concentrated, compressed, loaded into transportation cylinders ("tubes"), and trucked in gaseous form directly from processing equipment on a well pad to market. Or helium can be processed at another location off of the well pad containing the same helium recovery equipment and then trucked from there to market.

5. Alternatively, either the raw gas or crude helium can be processed at a facility (liquefaction plant) designed to purify and liquify helium to Grade A. Helium liquifies by cooling to approximately minus 269^{o}C (cryogenic).

6. The pricing premium on liquid helium is a reflection of its purity and the market demand for purity, rather than a reflection of the cost of converting gas to liquid. Demand for purity is demonstrated

by a buyer that may purchase market premium liquid helium only to re-gasify it according to user needs in manufacturing, research, medical, aerospace, and other sectors.

2.3 Publicly Available Helium Pricing

1. Gas is measured as a volume in cubic feet (CF). The volume at the well is typically measured in thousands using the Roman numeral “M”, where 1,000 cubic feet of gas is 1 MCF and 1,000 cubic feet of gas per day is 1 MCFD.
2. Helium does not have published commodity pricing. Pricing is determined by private transactions through contracts.
3. Companies and analysts report highly variable prices, such as post-2022 pricing from $250 MCF to $800 MCF, or more, depending on helium grade, price spikes from supply constraints, costs, transportation, and other factors.
4. States imposing a severance tax on production of helium may rely on information originating from operator revenue statements as the basis for computation of taxes.
    a. Revenue statements do not depend on publicly available commodity data.
    b. Revenue statements also cut across variable types of private helium transactions, from contracts, to auctions, to spot market sale.

2.4 Publicly Available Historical Helium Pricing

1. Unlike natural gas and oil, helium is not traded as a commodity on public markets that publish current pricing. Helium pricing is established through private transactions.
2. Operators may rely on industry knowledge, industry experts, and third-party consultants supporting helium contracts and transactions.
3. Publicly available information is available to identify recent *historical* helium production, pricing, and trends. A notable resource is the annual U.S. Geological Survey (USGS) *Mineral Commodity Summary*.
4. The table below summarizes the 10-year estimated prices per MCF for Grade A and crude helium sold from private industry to government users and from private industry to non-government users.

Year	Grade-A helium to government users (per MCF)	Crude helium to government users (per MCF)	Crude helium to non-government users (per MCF)
2023	$390	Not available	Not available
2022	$310	Not available	Not available
2021	$210	$100	$100
2020	$210	$86	$119
2019	$210	$86	$119
2018	$210	$86	$119
2017	$200	$83	$107
2016	$200	$84.40	$104
2015	$200	$85	$104
2014	$200	$69	$95
2013	$200	$67.75	$84

[1]U.S. Geological Survey, Helium Statistics and Information, Mineral Commodity Summaries for Helium, available at: https://www.usgs.gov/centers/national-minerals-information-center/helium-statistics-and-information

5. Two of the influences in the helium sector are noteworthy for understanding the helium market.
    a. There is no substitute for helium's unique properties in gaseous and liquid form for the sectors that rely on helium use.
    b. The Helium Stewardship Act of 2013 required the privatization of the decades-old federal helium reserve. Auctioning the federal reserve concluded in 2024. Former helium pricing metrics used by BLM's operation and sales from the federal reserve are now no longer part of the helium market.

U.S. Geological Survey, Mineral Commodity Summaries 2024
https://pubs.usgs.gov/periodicals/mcs2024/mcs2024.pdf and
https://www.usgs.gov/centers/national-minerals-information-center/mineral-commodity-summaries

3.0 Minnesota Environmental Quality Board

Environmental Review

3.1 Environmental Assessment Worksheet as Threshold Information

1. The Environmental Assessment Worksheet (EAW) represents an existing framework to obtain threshold information for a proposed operation.
2. Operator responses to the EAW can provide information necessary for review to issue a Development Permit and any site-specific permit conditions.
3. Information for the EAW would fall into two categories: operations and environmental, consistent with the current EAW form.
4. The Responsible Governmental Unit (RGU) retains discretion to make a finding that an Environmental Impact Statement is indicated, rather than an EAW, only.

3.2 Action Triggering EAW

1. The action triggering an EAW would be a request to DNR for a Development Permit.
2. An EAW completed by the operator can accompany the request for a Development Permit as baseline information.
3. The Development Permit and associated Drilling Permit would not be issued without EAW review and site-specific permit conditions resulting from information provided in the EAW or through DNR's independent review.

3.3 Timing for EAW Requirement

1. Submittal of the EAW can be concurrent with a request to DNR for a Development Permit.
2. The format of the request to DNR for a Development Permit will be determined by the agency. It may consist of a Development Permit application form and accompanying attachments.
3. The request to DNR for a Development Permit would make DNR the likely RGU for an EAW.
4. The EAW and Development Permit would be required prior to disturbing a new surface location to drill a gas well or install production equipment related to the gas well.
    a. Exploration wells would be considered gas wells subject to a Development Permit, regardless of whether the well was found to have economic volumes of gas for production.
5. The EAW content could use the existing EAW with modifications to better align with a gas operation.

3.4 Scope of Operations Subject to EAW

1. The scope of operations subject to the EAW can be all of the area disturbed for a well pad and all the operations at the well pad for exploration, production, treatment, and processing of gas, including:
    a. Production equipment consisting of surface equipment, and the flowlines on the well pad connecting the surface equipment, during the life of the well or processing operations on the pad
    b. Processing operations consisting of equipment on the well pad to separate, purify, compress, and store gas from the well and any liquids
    c. Flowline(s) and associated disturbance from the well pad to processing operations at another location

   d. Access road from the public road to the well pad

2. A stand-alone processing operation at another location would be regulated as an industrial facility, consistent with the regulation of other industrial facilities in the state, rather than subject to a Development Permit.

3.5 Modifications Needed to Current EAW Form

1. EAW (December 2022) is currently in circulation. Suggested modifications to the form are shown in the table below.

Section	Suggested Modification to EAW
1	• Change *Project title* to *Name of Operation* • Use operation throughout the EAW
2	• Change *Proposer* to *Operator* • Add line item for the company name of the operator
4	• Eliminate column for discretionary EAW
5	• Replace the requirement for *general* location with *proposed* location • For site plans, list the minimum information required to be shown: disturbed area and acreage; well pad and acreage; access from public road and length; flowline to processing operations at another location and length; setbacks from features identified by the EAW; equipment during well drilling and completion; equipment during production; stormwater controls
6b	• List a requirement for the estimated schedule and duration for construction, well drilling and completion, well testing, well shut in, and production • List a requirement to describe or illustrate process flow during production from the wellhead through the operator's final disposition of gas • List a requirement to describe the operations on the well pad, access road, flowline, stormwater control design, and power source during production • List a requirement to describe the equipment type and volume during well drilling and completion and during production, including any air pollution control and spill prevention
6c	• List a requirement to describe potential full buildout on the well pad • Detailed information for full buildout not otherwise provided in Section 5, 6b, and subsequent sections of the EAW would require amendment to the Development Permit and a new EAW
6d	• List a requirement to declare the mineral resource targeted for drilling and production from the well
6e	• List a requirement to describe where gas processing through the operator's final disposition of the gas will occur

Section	Suggested Modification to EAW
7	• May be addressed by other EAW sections
10	• List a requirement to show residential and non-commercial buildings within a designated distance from the proposed well pad • List a requirement to demonstrate a surface lease for surface use of the land
11b	• List a requirement to provide the anticipated schedule, size, revegetation plan, and stormwater controls to downsize the area of disturbance after well drilling is complete
12b	• List a requirement to provide anticipated volume, storage, and disposal of formation water during well drilling • List a requirement to provide anticipated volume, storage, and disposal of produced water for the life of the well • Sections can be edited for applicability to gas well development
13	• List a requirement for the type, volume, storage, and disposal of exploration and production waste, including drilling fluid, drill cuttings, cement returns, excess cement, tank bottoms, oily waste, well treatment chemicals, plugging fluids, and general domestic wastes
20	• List a requirement to quantify the number of days per week a site operator will be on location to inspect and maintain the location • List a requirement to quantify the number of truck trips per week to offload liquids or compressed product from the location
21b	• Indicate that reasonably foreseeable future projects can include gas processing operations at another location under the control of another operator

4.0 Minnesota Department of Health

Drilling Permit

4.1 When a Drilling Permit is Required

1. A Drilling Permit would be required prior to drilling a gas well
2. A Drilling Permit would be required prior to re-entering a plugged well
3. A Drilling Permit or amendment to an approved Drilling Permit would be required to deepen or complete a drilled well.

   Colorado Energy & Carbon Management Commission, Rule 308.a
   https://ecmc.state.co.us/documents/reg/Rules/LATEST/300%20Series%20-%20Permitting%20Process.pdf

4. A water well or stratigraphic well used for exploration or production of gas would require a Drilling Permit.
   a. If a test for gas or fluid productivity is made in a water well or stratigraphic well, the well would be reclassified as a gas well subject to a Drilling Permit.
   b. Montana states “If a test for fluid productivity is made in a stratigraphic well or core hole, the well must be reclassified as ‘wildcat or exploratory’ and is subject to all the rules of a well drilled for oil or gas.”
   c. Likewise in Montana, wells drilled in a delineated field to known productive horizons cannot be classified as stratigraphic wells.

   Montana Board of Oil and Gas Conservation, Rule 36.22.303
   https://rules.mt.gov/browse/collections/aec52c46-128e-4279-9068-8af5d5432d74/policies/06b92f4b-42bc-48fd-94f7-3b037b1c169b

4.2 Construction Engineering

1. The operator would be required to identify:
   a. Mineral ownership (e.g., fee, state)
   b. Mineral leasehold (to qtr qtr and acres)
   c. In Utah at Rule 649-3-4.2.4, operators must provide a plat prepared by a licensed surveyor or engineer showing:
      1) The well’s Public Land Survey System (PLSS) quarter-section or lot, section, township, range, and principal meridian
      2) Latitude and longitude coordinates for the well's surface and terminus locations
      3) Bearing and distance from the well's surface to its terminus location and from the surface and terminus locations to PLSS section lines
      4) Coordinate reference system
   d. In Colorado, the plat must show ground elevation
   e. Formation names, top depth, bottom depth
   f. Well type (vertical versus directional)
   g. Any proposed hydraulic fracturing

h. Whether salt sections are anticipated

i. Blowout prevention equipment

j. Total depth

1) Surface hole location

2) Bottom hole location

k. Drilling fluid type

l. Closed loop drilling

1) In Colorado at Rule 408.a, closed loop drilling is required except where only water-based bentonitic drilling fluids are used and the well will not penetrate salt-bearing formations.

2. Include waste disposal for drilling fluid, drill cuttings, cement returns, excess cement, tank bottoms, oily waste, well treatment chemicals, plugging fluids, and general domestic wastes addressed with surface use by the EAW submitted with the Development Permit.

4.3 Casing and Cementing

1. As a general requirement, casing and cementing is intended to prevent migration of gas and water from one formation to another behind the casing and to isolate groundwater penetrated by the well.

2. Casing and cementing requirements vary by state and show a continuum of requirements.

   a. Groundwater requirements, for example, range from casing to 50 feet below groundwater classified for domestic use, agricultural use, protection, or useable quality (Colorado) to casing 100 feet below all fresh water strata (Michigan).

   b. Centralizer requirements range from specific for every fourth joint for surface casing (Colorado) to the general requirement for spacing to maintain the casing annulus throughout the cased interval (Wyoming).

   c. Cementing requirements range from designating free water separation less than or equal to 3 mm per 250 mm of cement (Colorado) to designating only adherence to API standards (Wyoming).

3. In Colorado, casing and cementing requirements are found at Rule 408.

   In Michigan, casing and cementing requirements are found at Rule 324.

   In Montana, casing and cementing requirements are found at Rule 36.22.1001.

   In Utah, casing and cementing requirements are found at Rule 649-3-8.

   In Wyoming, casing and cementing requirements are found at Rule 055.0001.3.

4. Variation seen in state requirements tends to have a basis in local conditions. For example, protection may be put in place for critical groundwater. Or state engineers map apply their differing experience with results observed from cementing programs. Or local geology and geologic strata may affect additives and bonding in cement and drive specifications. Or compressive strength in cement may vary by well depth.

5. In general, although certain states (such as Kansas) may demonstrate specifications similar to Colorado, Colorado specifications illustrate a comprehensive model.

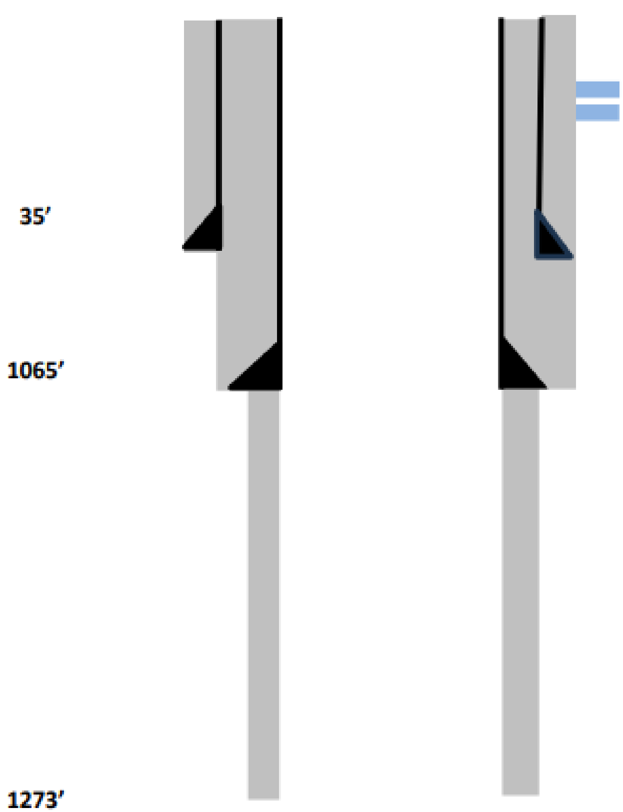
6. For additional support with casing, the American Society of Mechanical Engineers provides a reference for specifications.
7. For additional support with cementing, cement companies supplying oil and gas operations may provide a resource for expertise and an in-house database of cementing procedures across states.
8. Some jurisdictions (commonly counties) will conduct technical reviews requiring specialization with support from consulting engineers.
9. Below is an example illustration for reporting casing programs and wellbore diagram.

CASING PROGRAM

Casing Type	Size of Hole	Size of Casing	Grade	Wt/Ft	Csg/Liner Top	Setting Depth	Sacks Cmt	Cmt Btm	Cmt Top
CONDUCTOR	20+0/0	16+0/0	A500	52.49	0	10	10	10	0
SURF	12+1/4	8+5/8	J-55	24	0	630	400	630	0
1ST	7+7/8	5+1/2	J-55	15.5	0	6300	400	6300	3000
	7+7/8	5+1/2	J-55	Stage Tool		3000	250	3000	0

CASING PROGRAM

Casing Type	Size of Hole	Size of Casing	Grade	Wt/Ft	Csg/Liner Top	Setting Depth	Sacks Cmt	Cmt Btm	Cmt Top
CONDUCTOR	17+1/2	13+3/8	J-55	48	0	35	14	35	0
SURF	12+1/4	9+5/8	J-55	36	0	1065	196	1065	0
OPEN HOLE	8+3/4				1065	1273			



GL: ~5,548'

← Conductor Casing
13 3/8” 48# J-55 casing set at 35’. Cemented in a 17 1/2” hole with 14 sacks of 15.5# / 1.16 yield class G neat Cement to Surface. Hole depth 35’

← Surface String
9 5/8” 36# J-55 Casing set at 1065’. Cemented in a 12 1/4” hole with 196 sacks of 15.5# / 1.16 yield class G neat Cement to surface. Hole depth 1065’

← Open Hole
Drill 8 ¾” open hole to 1273’, Plan to produce from open hole.

TD of 1273’

Colorado Energy & Carbon Management Commission, Rule 408
https://ecmc.state.co.us/documents/reg/Rules/LATEST/400%20Series%20-%20Operations%20and%20Reporting.pdf

Michigan Geologic Resources Management Division, Rule 324
https://dtmb.state.mi.us/ORRDocs/AdminCode/1889_2019-001EQ_AdminCode.pdf

Montana Board of Oil and Gas Conservation, Rule 36.22.1001
https://rules.mt.gov/browse/collections/aec52c46-128e-4279-9068-8af5d5432d74/policies/9d86865b-b701-4323-a1bc-fb92ca29b565

Utah Division of Oil, Gas and Mining Rule 649-3
https://adminrules.utah.gov/public/rule/R649-3/Current%20Rules?searchText=R649

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.3
https://rules.wyo.gov/Search.aspx?mode=1

4.4 Well Integrity

1. Colorado requires at Rule 408 pressure testing the surface and intermediate casing to a minimum 1,500 pounds per square inch (psi) and the production casing to a minimum 500 psi greater than the maximum anticipated surface pressure.
    a. The operator must submit results for integrity testing, a cement bond log, and a resistivity log to describe the stratigraphy of the wellbore.
2. Wyoming requires at Rule 055.0001.3 pressure testing to a surface pressure of 1,500 psig.
    a. The operator must submit results for integrity testing and a cement bond log.

Colorado Energy & Carbon Management Commission, Rule 408
https://ecmc.state.co.us/documents/reg/Rules/LATEST/400%20Series%20-%20Operations%20and%20Reporting.pdf

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.3
https://rules.wyo.gov/Search.aspx?mode=1

4.5 Well Plugging

1. The Drilling Permit application can include planned plugging and abandonment procedures.
2. The purpose of a plan to properly and permanently plug and abandon the well is to prevent potential environmental and safety concerns from unmonitored and non-producing wells.
3. Proper well closure also facilitates restoration of the surface location.
4. The financial assurance for the well would not be released until proper well plugging, abandonment, and surface reclamation have been verified.
5. Multiple states, such as Colorado, Kansas, Michigan, Montana, North Dakota, and Wyoming, evidence a common baseline for plugging requirements:
    a. Abandonment notice
    b. Cementing
    c. Removal of surface equipment
    d. Site reclamation

e. Abandonment report

f. Bonding

6. In Colorado at Rule 406.e for an abandoned conductor:

    a. Once a conductor pipe is set, if the well is not drilled within 3 months for cropland or 6 months for non-cropland, the well must be plugged.

    b. The conductor pipe must be cut 4 feet below ground level.

    c. The conductor pipe must be filled with clean inert material

    d. The conductor pipe must be sealed with a cement plug, screw cap, or cement plug and welded steel plate.

    e. The hole must be backfilled to ground level.

7. In Colorado at Rule 434.a for an abandoned well:

    a. Once a drilled well become inactive, it must be plugged and abandoned within 6 months.

        1) In Kansas, Montana, and Wyoming this timeframe increases to 1 year.

    b. The wellbore must be static before setting a plug.

        1) Wellbore fluids must be circulated to balance or overbalance the producing formation.

    c. The operator must pump cement plugs, with any plug a minimum 100 feet long and extending a minimum 100 feet above each zone to be isolated.

        1) In Kansas, the required lengths are 50 feet.

    d. Between cement plugs, the operator must fill the bore with water, mud, or other approved fluid.

    e. Cement design standards are listed at Rule 434.a.(1).

        1) In Wyoming, operators are referred to API standards for the class of cement and additives

    f. Abandonment procedures and marking at the surface are listed in Rule 434.a.(5).

Colorado Energy & Carbon Management Commission, Rule 400
https://ecmc.state.co.us/documents/reg/Rules/LATEST/400%20Series%20-%20Operations%20and%20Reporting.pdf

Kansas Corporation Commission, Rule 82-3-1010
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

Montana Board of Oil & Gas Conservation, Rule 36.22:
https://rules.mt.gov/browse/collections/aec52c46-128e-4279-9068-8af5d5432d74/sections/938ab68e-ff7e-4a24-b69f-1eccc48453b2

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.3, Section 18
https://rules.wyo.gov/Search.aspx?mode=1

4.6 Blowout Prevention

1. Operators are expected to take all necessary precautions to maintain control of the well throughout all phases of operation (drilling, deepening, re-entry, re-completion, workovers, production, and plugging).
    a. Control of the well requires measures to prevent uncontrolled releases (blowouts) using equipment appropriate to the well, installation, and testing.
2. Helium gas wells may experience pressures significantly lower than a hydrocarbon gas well. Like the rules listed below, the operator can indicate the anticipated pressures and corresponding equipment.
3. In Colorado at Rule 603, the operator must indicate the type of blowout prevention equipment ("BOPE") in the drilling application.
    a. The operator must also indicate any known subsurface conditions, such as an under or over-pressured formation.
    b. The blowout prevention equipment working pressure must exceed the anticipated surface pressure, assuming a pressure gradient of 0.22 psi per foot.
4. In Wyoming at Rule 055.0001.3, Section 23, blowout prevention equipment must be based on known or anticipated subsurface pressure, geologic conditions, or accepted engineering practice
    a. Wyoming, like Colorado, provides a standard for estimating the pressure to be contained at the surface of 0.22 psi per foot.
    b. Wyoming rules specify requirements for installation and testing.
5. Montana requirements for blowout prevention at Rule 36.22.1014 are linked below.

Colorado Energy & Carbon Management Commission, Rule 603
https://ecmc.state.co.us/documents/reg/Rules/LATEST/600%20Series%20-%20Safety%20and%20Facility%20Operations%20Regulations.pdf

Montana Board of Oil & Gas Conservation, Rule 36.22:
https://rules.mt.gov/browse/collections/aec52c46-128e-4279-9068-8af5d5432d74/policies/de9b4283-bf47-4cc9-b2d5-86103e3da0ea

Wyoming Oil & Gas Conservation Commission, Rule 055.0001.3, Section 23
https://rules.wyo.gov/Search.aspx?mode=1

5.0 Minnesota Pollution Control Agency

Air Emissions

5.1 Venting and Flaring

1. Colorado example for the well:

    a. ECMC rules prohibit venting or flaring gas during production. Venting or flaring under the circumstances below may be approved by the Director:

        1) During drilling, operators may vent with procedures for providing verbal notification to ECMC if capturing or combusting gas poses a safety risk to onsite personnel.

        2) During completions, operators may flare gas under an approved Gas Capture Plan with written approval from ECMC, including requirements to explain why flaring is necessary; protect public health and safety; estimate the flaring volume and duration; and direct gas to an emission control device for combustion if necessary.

    Colorado Energy & Carbon Management Commission, Rule 903
    https://ecmc.state.co.us/documents/reg/Rules/LATEST/900%20Series%20-%20Environmental%20Impact%20Prevention.pdf

2. New Mexico example for the well:

    a. Venting or flaring natural gas during drilling and completion is generally prohibited but may be done under certain circumstances.

    b. In all cases, flaring is preferred over venting except when (i) flaring is technically infeasible or would pose a risk to safe operations or personnel safety and (ii) venting is a safer alternative than flaring.

    c. During drilling in an emergency situation or malfunction, the operator may vent natural gas to avoid risk of an immediate and substantial adverse impact on safety, public health, or the environment.

        1) “Natural gas” is defined as “a gaseous mixture of hydrocarbon compounds, primarily composed of methane, and includes both casinghead gas and gas as those terms are defined in 19.15.2 NMAC." Based on this definition, the New Mexico regulations on venting and flaring may not apply to helium gas with a low hydrocarbon percentage.

    New Mexico Oil Conservation Division, N.M. Admin. Code 19.15.27.8, NMAC 19.15.27.7O
    https://www.srca.nm.gov/parts/title19/19.015.0027.html

3. Kansas example for the well:

    a. Operators may flare, vent, or use gas in any manner as authorized by regulations of the Kansas Corporation Commission, depending on the type of gas:

        1) Casinghead gas less than 25 mcfd may be vented or flared if (1) the gas volume is uneconomic to market due to pipeline or marketing expenses and (2) the operator made a diligent effort to obtain a market for the gas.

        2) Casinghead gas greater than 25 mcfd may be vented or flared considering (1) the availability of a market or of pipeline facilities; (2) the probable recoverable gas reserves; (3) the necessity for maintenance of reservoir gas pressure to maximize recoverability; (4) the feasibility of reinjecting the gas; and (5) other factors.

3) Sour casinghead gas is gas high in hydrogen sulfide (H2S) and may be flared considering (1) the availability of a market or of pipeline facilities; (2) the probable recoverable gas reserves; (3) the necessity for maintenance of reservoir gas pressure to maximize recoverability; (4) the feasibility of reinjecting the gas; (5) any anticipated change in the gas-to-oil ratio; (6) the H2S content of the gas; (7) the feasibility of desulfurization of the gas; and (8) other factors.

4) Natural gas may be vented or flared if necessary for any of the following: dewatering or well cleanup; well testing; well cleanup after stimulation or workover; evaluation and testing before connecting to a pipeline; emergencies; or as otherwise permitted by statute.

Kansas Corporation Commission, Rule 82-3-208
https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

4. Colorado example for storage tanks

   a. Storage tanks with uncontrolled actual emissions of volatile organic compounds (VOCs) equal to or greater than 2 tons per year (tpy) based on a rolling 12-month total must collect and control emissions.

   b. Emissions must route from each storage tank to operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95 percent. Use of a combustion device must have a design destruction efficiency for hydrocarbons of at least 98 percent.

   c. Venting is not allowed from a thief hatch, pressure relief device, or other access to the tank during normal operation, unless venting is reasonably required for maintenance.

   d. If air pollution control equipment is not installed by the compliance date, the operator may shut in wells producing into that storage tank until the control equipment is installed and operational.

   e. If use of air pollution control equipment would be technically infeasible without supplemental fuel, the operator may apply for an exemption from control requirements, but monitoring requirements would still apply.

   f. Monitoring is required at the frequency below.

Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Monitoring Frequency
≥ 2 and ≤ 12	Semi-annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

Colorado Air Quality Control Commission, Regulation No. 7 (5 CCR 1001-9)
https://drive.google.com/file/d/1P6pRmNYx5KwEK6qDReYFL11-K-URI33J/view

5. New Mexico example for storage tanks:

   a. New storage vessels with a potential to emit (PTE) equal to or greater than 2 tpy of VOC must have combined capture and control of VOC emissions with at least 95 percent control upon start up. Use of a combustion device must have a design destruction efficiency for hydrocarbons of at least 98 percent.

   b. Storage vessels with a thief hatch must be capable of opening sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved.

c. If a control device is not installed by the compliance date, the operator may comply by shutting in the well supplying the storage vessel and not resume production from the well until the control device is installed and operational.

d. The requirements do not apply to a storage vessel if the actual annual VOC emissions decrease to below 2 tpy.

e. Monthly inspection of the storage vessel must ensure compliance with control requirements. Audio, visual, olfactory (AVO) inspection must be conducted weekly.

New Mexico Environmental Improvement Board, N.M. Admin. Code 20.2.50.123
https://www.srca.nm.gov/parts/title20/20.002.0050.html

6. Federal NSPS OOOOb

a. In March 2024, the U.S. Environmental Protection Agency (EPA) finalized federal New Source Performance Standards (NSPS) to reduce air pollution emissions, specifically VOC and methane, from the Crude Oil and Natural Gas source category ("NSPS OOOOb"). *See* 89 Fed. Reg. 16820 (March 8, 2024); 40 C.F.R. § 60.5360b *et seq*.

b. NSPS OOOOb is applicable to affected facilities that began construction, reconstruction, or modification after December 6, 2022. *See* 40 C.F.R. § 60.5365b.

c. The types of source categories regulated by NSPS OOOOb include process controllers (previously referred to as pneumatic controllers), pumps, centrifugal compressors, storage vessels, combustion control devices, and liquids unloading.

d. Under the NSPS, a storage vessel affected facility is generally a tank battery that has the potential for VOC or methane emissions that is equal to or greater than either (1) 6 tpy VOC or (2) 20 tpy methane.

e. The Operator must reduce VOC and methane emissions by at least 95 percent by routing emissions to a control device or process under requirements specified in the rule, or by using a tank with a floating roof.

f. The rule allows for removal of a control device from a storage vessel if the operator maintains the uncontrolled actual VOC emissions at less than 4 tpy and the actual methane emissions at less than 14 tpy as determined monthly for 12 consecutive months.

g. The operator must demonstrate compliance with the 95 percent reduction requirement by conducting performance tests in accordance with the control device testing requirements.

U.S. Environmental Protection Agency, 40 C.F.R. § 60.5395b ("NSPS OOOOb")
https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-OOOOb/section-60.5395b

5.2 Stationary Engines

1. Engines for drilling and production are likely to be used for the following:

a. Non-road internal combustion engine on the drill rig

b. Non-road internal combustion engine on the completions rig

c. Stationary source engine(s) powering air compressors

d. Stationary source engine(s) powering helium processing equipment when grid power is unavailable

2. Rig engines typically use diesel fuel to supply the rig generator and provide sufficient power for drilling. Air emission controls range from Tier II to IV, depending on the age of the drill rig and rig availability. The rigs are regulated as non-road engines.
    a. Certain rigs are capable of lowering emissions by running on dual fuel or by using natural gas from the well.
    b. Certain rigs are capable of lowering emissions by running on electricity from the power grid, which requires a specialized transformer connecting to the rig's powerhouse.
    c. In general, the duration for drilling and completing a relatively shallow gas well in an area that is in attainment for National Ambient Air Quality Standards can provide for flexibility in the emission controls required for the drilling and completions rigs.
3. During well drilling, stationary engines may be used to power air compressors used for drilling.
4. During production, stationary engines may be used to power helium processing equipment when no grid power is available.
    a. Stationary engines during production are more likely to be powered by natural gas or propane.
5. Stationary engines are already regulated in Minnesota by PCA depending on the source's PTE as a product of engine make and model, fuel type, fuel use, horsepower, displacement, emission controls, and assumption of operating hours (8,760 hours per year).

5.3 Odor Control

1. Gas wells drilled with water-based drilling fluid ("mud") or air would typically not have the nuisance odors that might be associated with operations using oil-based drilling fluids and oil tank storage.
2. Nuisance odors can be further controlled in the following ways:
    a. Closed-loop system during well drilling to reuse drilling fluid
    b. Fluid storage in steel tanks, which are removed from the location after well drilling for off-site disposal
    c. Drill cutting storage in steel tanks, which are removed from the location after well drilling for off-site disposal
    d. When oil-based mud is used (e.g., for salt sections in the formation), the oil-based mud that is not part of the active mud system would be stored in closed upright tanks
    e. Prohibition on burning debris and trash
    f. Liquids stored during production would use enclosed tanks maintained with closed thief hatches
    g. Operators would comply with local nuisance ordinances

5.4 Noise Control

1. Gas wells would typically not have nuisance levels of noise when drilled (1) in a rural area distanced from homes and businesses, (2) over a relatively short duration for a conventional vertical well, and (3) without hydraulic fracturing.
2. Nuisance noise can be further controlled in the following ways:
    a. Perform an estimate of sound levels at the nearest receptors, where sound levels in a rural residential area may be expected in the range of 50 to 60 decibels measured in dBA

b. Compliance with a local ordinance establishing daytime and nighttime noise limits

c. Installation of a sound wall during well drilling in the direction of receptors, if needed

d. Installation of enclosures for long-term use of generators during production

e. Electrification of the site to connect powered equipment to the electric grid during production, in lieu of generator use

3. Colorado and New Mexico establish numeric limits for noise based on land use and time of day.

Colorado Energy & Carbon Management Commission, Rule 423
400 Series - Operations and Reporting.pdf (state.co.us)

New Mexico Oil Conservation Division, Rule 802.a
COGCC_800_Series_VF_Current.pdf (nm.gov)

Water Discharges

5.5 Disposing of Formation Water

1. During well drilling, water may be present in the formation (“formation water”).
2. Water brought to the surface from the well as formation water would typically be stored at the surface in tanks.
3. Tanks commonly in use during well drilling are 500-barrel (bbl) open-topped rectangular steel “frac tanks.”
   a. 500 bbls is equivalent to approximately 21,000 gallons.
4. Formation water would have a composition unique to the gas reservoir and may contain suspended solids, dissolved solids, soluble and insoluble organics, and hydrocarbons.
5. Formation water may also contain technologically enhanced naturally occurring radioactive material (TENORM). Technologically enhanced refers to the human-caused exposure or concentration of radioactive material not otherwise exposed to the surface.
6. Disposing of formation water during well drilling, like produced water during production, would require piping or trucking off-site to a facility approved to accept the waste, which is discussed further below.

5.6 Disposing of Produced Water

1. After well drilling, water may continue to be present in the formation.
2. Water brought to the surface from the well as produced water would typically be separated from the gas stream using a two-phase separator for water and gas.
   a. If oil was present in the formation, the streams would typically be separated using a three-phase separator or a heated separator to separate water, gas, and oil.
3. Produced water is commonly stored in aboveground storage tanks, ranging from 200 bbls to 300, 400, or 500 bbls.
4. Minnesota PCA regulates aboveground storage tanks, except at Section 115.03 in Minnesota statute where tanks are used for storing liquids that are gaseous at atmospheric temperature and pressure.

a. Produced water is not gaseous at atmospheric temperature and pressure, although the tank may experience breathing loss of hydrocarbons from changes in temperature or pressure.

5. Methods for disposal of formation water and produced water from a well include (1) injection well, (2) surface discharge, (3) pretreatment and disposal at a publicly owned treatment works (POTW), and (4) land application.

    a. Oil and gas producing states rely predominantly on injection well disposal.

6. Injection wells

    a. Minnesota has determined that use of injection wells for oil and gas-related disposal or injection is not prohibited under Rule 4725.2050 administered by MDH.

    b. However, Minnesota has not been delegated primacy by EPA for regulation of oil and gas-related Class II "Underground Injection Control" (UIC) wells.

    c. Class II injection wells in Minnesota would be regulated directly by EPA (direct implementation) under federal rules implementing the Clean Water Act.

    d. EPA provides a *Class II Permit Application Completeness Review Checklist* summarizing the information required from an applicant for mapping; geological data; formation testing; well construction; injection operation; injection monitoring; plugging and abandonment; and financial assurance.

    e. One opportunity in Minnesota would be pairing a state-issued Development Permit for the surface location with an EPA-issued Class II UIC permit for the injection well to protect surface and subsurface resources.

    f. In the neighboring states of North Dakota and South Dakota, Class II injection wells are regulated by the North Dakota Department of Mineral Resources and the South Dakota Department of Agriculture & Natural Resources.

        a. Class II injection wells in neighboring states present an opportunity for trucking formation water and produced water out of state for disposal.

U.S. Environmental Protection Agency, UIC Class II Permit Application Completeness Review Checklist
https://www.epa.gov/sites/default/files/2019-08/documents/solution_2.2_-_class_ii_administrative_review_checklist_draft_final.pdf

7. Direct discharge

    a. Direct discharge of produced water potentially would be regulated according to federal New Source Performance Standards for onshore oil and gas extraction under EPA effluent limit guidelines at 40 Code of Federal Regulations (CFR) Part 435, Subpart C.

8. Pretreatment

    a. Pretreatment and discharge of produced water from an *unconventional* oil and gas well (e.g., tight shales) to a POTW is prohibited under 40 CFR Part 435.34.a. In its guidance, EPA states that POTWs are not designed to treat constituents present in the effluent.

    b. Rules regarding pretreatment and discharge of produced water from a *conventional* oil and gas well to a POTW is currently reserved for future federal rulemaking at 40 CFR Part 435.34.b.

9. Land application
    a. Land application of produced water is regulated in multiple states, such as New Mexico, Texas, and Wyoming.
    b. Land application can be associated with environmental degradation from salts, measured as sodium absorption ratio and electrical conductivity, and the associated potential impacts to soil productivity, vegetation, surface water and groundwater.
    c. To protect the land surface, surface water, and groundwater, regulatory programs review wastewater quality and waste loading, application method, application rate, soil characteristics, topography, runoff control, and depth to groundwater.

5.7 Use of Pits

1. Anticipated waste streams may include drilling fluid, drill cuttings, formation water, cement returns, excess cement, produced water, tank bottoms, oily waste, well treatment chemicals, plugging fluids, and general domestic wastes.
2. Advance planning for waste disposal is particularly important for an area without an existing oil and gas sector and a commercial sector established to serve oil and gas sector waste disposal.
3. The EAW provides a means to require the operator’s plan for waste disposal for each anticipated waste stream.
4. *Off-site* waste disposal at facilities approved to accept the waste would typically be the preferred method of disposal.
5. The method for waste disposal, including any requirement for off-site waste disposal, could be a provision in the Development and Drilling Permits.
6. At some well sites, operators may seek approval to excavate a pit to serve as a temporary holding area for waste fluids or approval to excavate a trench for permanent disposal for drill cuttings.
    a. Trenches for drill cuttings typically are unlined to allow drill cuttings to dewater and dry for burial.
    b. Pits for waste fluids typically are lined to prevent contamination of soil and groundwater.
7. When pits are allowed, prohibitions may be placed on areas with shallow groundwater, in floodplains, or with nearby residences.
8. Drill cuttings burial on site is allowed in Colorado only when the drill cuttings meet concentration limits for pollutants listed in Table 915-1 after composite sampling.
9. Pits used for waste fluids in Colorado must meet construction, liner, and closure requirements at Rules 909-911.
10. States vary as shown below in stringency for pits used for waste fluids.
    a. Required pit freeboard in Colorado at Rule 909.c is 2 feet. Required pit freeboard in Kansas at Rule 82-3-601a.(a) is 1 foot.
    b. Colorado requires at Rule 910.a that all new pits are lined. Kansas at Rule 82-3-600.(f)(2) requires a liner if the commission determines that an unsealed condition presents a pollution threat to soil or water.
    c. Colorado requires at Rule 910.c.(1) lining using a synthetic material. Kansas at Rule 82-3-601.a.(b) allows for liners to be composed of soils mixed with clay and bentonite.

11. Consistent with rules in Kansas, Wyoming rules at Rule 055.0001.4.w require liners under specific conditions, such as locations in fill, sandy soil, or areas with shallow groundwater. Liners can include clay mixtures. In Wyoming, freeboard is not quantified. Instead, the pit must be designed for extreme precipitation.

12. In general, states consistently specify rules for waste characterization, pit construction, natural or synthetic liner installation, hydraulic conductivity, leak detection, and closure.

    Colorado Energy & Carbon Management Commission, Rules 909-911, Table 915-1
    https://ecmc.state.co.us/documents/reg/Rules/LATEST/900%20Series%20-%20Environmental%20Impact%20Prevention.pdf

    Kansas Corporation Commission, Rule 82-3-600
    https://www.kcc.ks.gov/images/PDFs/oil-gas/conservation/cons_rr_091615.pdf

    Wyoming Oil & Gas Conservation Commission, Rule 055.0001.4.w
    https://rules.wyo.gov/Search.aspx?mode=1

5.8 Use of Water Tanks

1. For wells without formation or produced water, water at the site may only be the fresh water tanks used during well drilling and cementing.
2. Alternatively, an operator's water tank may refer to formation water during well drilling that is stored temporarily before off-site disposal.
3. An operator's water tank may also refer to one or more water tanks used to store produced water during production.
    a. Produced water may be present from the well during the life of the well.
    b. Or produced water may decline steeply after initial production.
4. A produced water tank will remain liquid at atmospheric temperature and pressure. A produced water tank should not be conflated with the exemption provided for compressed gas tanks.
5. Operators refer to tank volumes in barrels (bbls), typically ranging from 200 bbls to 300, 400, or 500 bbls, where 1 barrel is approximately 42 gallons.
6. Minnesota PCA already regulates aboveground storage tanks (ASTs) under regulations likely applicable to produced water tanks at Minnesota Administrative Rule 7151.

6.0 Residual Questions and Answers

Minnesota Department of Natural Resources

How are States Structured for Oil and Gas Regulatory Bodies?

Each oil and gas state reviewed has an organizational structure designated for administration of oil and gas rules. Less than one-third are independent bodies of the executive branch. The others are regulatory agencies under the executive branch.

Independent bodies of the executive branch:

Montana Board of Oil & Gas Conservation[1]

Nebraska Oil & Gas Conservation Commission

Wyoming Oil & Gas Conservation Commission

Regulatory agencies under the executive branch:

Colorado Energy & Carbon Management Commission, Department of Natural Resources

Kansas Oil & Gas Conservation Division, Kansas Corporation Commission

Michigan Geologic Resources Mgmt. Division, Dept. of Environment, Great Lakes, and Energy

New Mexico Oil Conservation Division, Energy, Minerals and Natural Resources Department

North Dakota Oil & Gas Division, Department of Mineral Resources

Pennsylvania Office of Oil and Gas Management, Department of Environmental Protection

South Dakota Minerals and Mining Program, Department of Agriculture & Natural Resources

Utah Division of Oil, Gas & Mining, Department of Natural Resources

[1]The Board states that it is attached to the Department of Natural Resources for *administrative* purposes

How are Oil and Gas Commissions Funded?

In oil and gas states, like Colorado and Kansas, commissions are not funded by appropriations from the general fund. Instead, they are largely fee funded by industry. In Colorado, for example, funding sources are a combination of a levy of 1.5 mills on oil and gas production; an operator fee for each well spud; an allocation from state severance taxes on oil and gas; and smaller funding streams from collected penalties, claimed financial assurance, and federal funds. An example of federal funds is a federal grant awarded in 2024 to plug methane-emitting oil and gas wells. In Colorado, the most recent fiscal year 2024 had an Energy & Carbon Management Commission budget of $32.5M.

Even in a smaller oil and gas state, like Nebraska, with a fiscal year 2024 budget of $1.7M, appropriation from the General Fund represented approximately 10 percent of the budget. The majority of funding was derived from industry and a small revenue stream from federal funds.

Minnesota Pollution Control Agency

Are There Anticipated Releases to the Atmosphere?

A helium well could be expected to produce nitrogen, CO_2, helium and, potentially, methane. Production may be free flowing gas or may include some amount of water from the underground formation. Processing equipment can provide for recovery of commercial grade CO_2 (e.g., used in the beverage industry) and helium. When CO_2 is not recovered for commercial sale, both nitrogen and CO_2 tend to be vented to the atmosphere. In states tracking greenhouse gases, such as Colorado, CO_2 emissions are an annual reporting requirement as part of a regulated source's annual emissions inventory. Methane gas in small volumes with no takeaway capacity (like a pipeline) can be routed on site to use as a fuel source for separation and processing equipment on the site. Or methane can be combusted in an enclosed combustor on the site with a greater than 98 percent destruction efficiency. See Section 1.6 for discussion of methane gas.

Is There Anticipated Long-term Storage of Gases in Tanks?

Gas in storage would be anticipated to be purified helium stored in iso tubes and loaded onto a semi-truck trailer for transport for commercial sale. See Section 2.2 for discussion of helium purification. Depending on production rates, a "tube trailer" may leave a site multiple days a week, which limits the time that iso tubes are stored on location. The iso tubes load horizontally on the trailer and are filled with inert, nonhazardous, and noncombustible compressed helium gas.

Is There Anticipated High-pressure Storage of Liquids in Tanks?

High-pressure tanks may be limited to iso tubes containing inert, nonhazardous, and noncombustible compressed helium gas. If formation water is encountered, it can be separated from the gas stream using a separator at the surface. The formation water can be stored in an enclosed tank at the surface at atmospheric pressure. Any gas vented from the tank can be captured for combustion in an enclosed combustor on site. Water from the tank can be off-loaded by truck and transported to a facility approved to accept the water for disposal. The water may be entrained with suspended solids, dissolved solids, soluble and insoluble organics, hydrocarbons, and possibly TENORMs. See Sections 5.1.4 and 5.5 for discussion of storage and regulation of gases and water using atmospheric storage tanks.

Is There Potential for a Small Quantity Generator for Hazardous Waste?

Wastes during well drilling (e.g., drill cuttings) and production (e.g., produced water and tank bottoms) are generally treated as federally exempt exploration and production ("E&P") waste under the federal Resource Conservation and Recovery Act, Subtitle C. Wastes not categorized as E&P wastes would be regulated under RCRA Subtitles C and D and corresponding state rules for waste management.

What is the Applicability of Federal Clean Air Act Section 112(r) to Operations?

Clean Air Act Section 112(r) requires a risk management program for certain stationary sources holding more than a threshold quantity of a regulated hazardous substance. In the implementing regulations at 40 CFR Part 68.115, exemptions are described at Part 68.115(b)(2)(iii) for naturally occurring hydrocarbon mixtures. According to the rule, these include any combination of condensate, field gas, and produced water. Irrespective of Clean Air Act Section 112(r), Minnesota regulatory requirements applicable to an operation may include generation of information in the Environmental Assessment Worksheet for the type, volume, storage, and disposal of exploration and production waste; state hazardous waste generator requirements; applicable Spill Prevention, Control, and Countermeasure Plan requirements; and any requirements imposed under a Development Permit for spill or release prevention, reporting, and response.

Is There Potential for Underground Storage Tanks?

During well development, temporary storage is expected to be above-ground. During production, a site with limited production facilities may be visited either daily or several days a week by outside personnel fueling their work vehicles off site. A site with production facilities to process helium may connect to grid power to power equipment. Without grid power, the site may use a combination of any recovered methane and imported fuel, like propane or natural gas (methane), to fuel generators. Those fuel tanks would likely be above ground and regulated consistent with state regulation for above ground storage tanks for fuel.

Is There Precedent for Well Driller Licensure?

Oil and gas well drilling does not appear to have the equivalent of states' requirement for the testing and licensure applicable to *water* well drillers. States like Texas emphasize that state licensure for water well drillers is in place to ensure construction integrity and safety for consumption from water wells. In the oil and gas sector, states may require licensure of the drill rig while otherwise using rules for casing, cementing, mechanical integrity, inspection, and reporting to govern the well driller and well.

Are Polyfluoroalkyl Substances Present in the Industry?

There is potential, for example, for on-site helium processing equipment to use fluoropolymer membranes for the separation of gases. Fluoropolymers are considered a type of polyfluoroalkyls (PFAS).

Conclusion

This Report of Best Practices does not identify singular best practices. Instead, it frequently provides multiple examples or continuums of practices that are seen across oil and gas producing states. Differences between states in their regulation of the oil and gas sector often reflect state-specific concerns, like population growth proximate to oil and gas development; air quality attainment status; prevalence of hydraulic fracturing in well drilling; sensitive groundwater resources; and other localized influences.

For each regulatory topic, the states or the number of states identified as precedents vary. The variation occurs because the focus is not on providing a fixed format for the report. Rather, the report provides models for regulatory practices most relevant to a topic. Given the many states and agencies identified in the report, the table below provides a collated list of agency links.

Regulatory Body	URL
COLORADO	
Energy & Carbon Management Commission, Department of Natural Resources	https://ecmc.state.co.us/#/home
ILLINOIS	
Oil & Gas Resource Management, Department of Natural Resources	https://dnr.illinois.gov/oilandgas.html
KANSAS	
Oil & Gas Conservation Division, Kansas Corporation Commission	https://www.kcc.ks.gov/oil-gas
MICHIGAN	
Geologic Resources Management Division, Dept. of Environment, Great Lakes, and Energy	https://www.michigan.gov/egle/about/organization/geologic-resources-management/oil-and-gas
MONTANA	
Board of Oil & Gas Conservation	https://dnrc.mt.gov/bogc/
NEBRASKA	
Oil & Gas Conservation Commission	https://nogcc.ne.gov/
NEW MEXICO	
Oil Conservation Division, Energy, Minerals and Natural Resources Dept.	https://www.emnrd.nm.gov/ocd/
NORTH DAKOTA	
Oil & Gas Division, Department of Mineral Resources	https://www.dmr.nd.gov/oilgas/
PENNSYLVANIA	
Office of Oil and Gas Management, Department of Environmental Protection	https://www.dep.pa.gov/Business/Energy/OilandGasPrograms
SOUTH DAKOTA	
Minerals and Mining Program, Department of Agriculture & Natural Resources	https://danr.sd.gov/Environment/MineralsMining/default.aspx
UTAH	
Division of Oil, Gas & Mining, Department of Natural Resources	https://ogm.utah.gov/og-home/
WYOMING	
Oil & Gas Conservation Commission	https://wogcc.wyo.gov/