# Chapter 29

# Oil and Gas*

## I. INTRODUCTION—REGULATION OF OIL AND GAS DEVELOPMENT



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## I. INTRODUCTION—REGULATION OF OIL AND GAS DEVELOPMENT

## § 29:1 General

Various statutes task state, federal, and tribal agencies and officials and local governments with protection of human health and the environment and with assuring the safe, efficient, and reasonable production and transportation of oil and gas. The statutes that are the subject of most of this treatise relate to the regulation of oil and gas development on federal and private lands at every stage of the oil and gas development process—leasing, exploration, drilling, production, transportation, storage, refining, and marketing. Although some statutes, like the Oil Pollution Act and Natural Gas Act, relate specifically to oil and gas, many of the environmental statutes discussed herein were not specifically enacted for the purpose of regulating oil and gas. Rather, these statutes are unique in aspects of their application to oil and gas development. Even so, these statutes alone do not constitute the full extent of environmental governance of oil and gas development. Other sources of governance include obligations within contracts and encumbrances on land and common law rules related to trespass, waste, and nuisance.

The terms oil and gas, as referred to herein, refer to combustible hydrocarbons and, at times, other materials produced in association therewith. Oil and gas interests are classified as mineral interests and may be separately conveyed as an interest in real property. When produced, the oil or gas is severed from the realty and becomes personal property—which can be stored, transported, and marketed as either a gas or liquid and refined into a variety of consumer products. As the cases and laws described herein demonstrate, production of these valuable products also involves complex industrial processes with risks and environmental impacts. The land use and environmental statutes discussed herein at times provide regulators with tools to assess these risks and limit or prevent environmental harms and in others to promote and encourage new development in order to serve public demand for oil and gas and related products.

## § 29:2 History of Oil and Gas Development in the United States

Though oil seeps and hand dug wells had been discovered and produced small amounts of oil much earlier, most scholars cite Drake's discovery at Titusville Pennsylvania in 1859 as the first oil boom and the beginning of the American oil and gas industry.[1] The events that followed—land speculation, a feverish race to produce, over drilling and environmental damage, and the subsequent decline of production and economic collapse and bust of the nascent local industry—have been repeated numerous times in basins across the country. Though early wells were most often shallow, vertical wells, these trends have continued through discovery of new resource plays and following the application of new technologies.

The growth of the early oil and gas industry also precipitated legal changes throughout the late 19th and early 20th century: Courts were tasked with determining the law relative to the nature of property interests in minerals and the rights of parties within oil and gas reservoirs;[2] Congress, realizing that grants made pursuant to early land disposition laws had conveyed away tremendous mineral resources, passed new laws that reserved federal minerals and created split estates;[3] To stem the land grab for placer-oil mining claims on public lands, President Taft withdrew lands in California and Wyoming, paving the way for the modern mineral leasing

**[Section 29:2]**

[1] DANIEL YURGIN, THE PRIZE: THE EPIC QUEST FOR OIL, MONEY & POWER 30 (2008).

[2] Wettengel v. Gormley, 160 Pa. 559, 28 A. 934 (1894).

[3] Stock-Raising Homestead Act, ch. 9, 39 Stat. 862 (1916) (current version at 43 U.S.C. § 299 (2020)).

system;[4] State legislatures, faced with high-risk technologies such as well shooting with nitroglycerine, passed laws limiting the quantities that could be brought into and stored within city limits.[5] These laws, and numerous others like them, established the balance between state and federal regulatory authority over oil and gas development and defined property interests in oil and gas, establishing precedents which have since given rise to the contemporary system of conservation regulation and administrative management.

In the last two decades, new technologies and concerns related to environmental impacts and climate have reshaped environmental regulation of the oil and gas industry. The successful application of horizontal drilling technology to unconventional "tight" formations in 2005 initiated a new drilling "boom" in shale formations across the United States which again reshaped the American energy landscape.[6] Although horizontal and directional drilling had been used successfully in both North Dakota and Texas in the 1980's, developers in the Barnett Shale in Texas found that, when combined with hydraulic fracturing technology, it opened up entirely new sources of natural gas.[7] The resultant boom caused a dramatic increase in United States natural gas production and also an increase in production of associated fluids and brines, called "produced water." This, in turn, gave rise to new environmental issues related to chemicals within fracturing fluids and to the seismic impacts resulting from injection of produced water.[8] Additionally, courts, legislatures, and local governments were confronted with new legal issues related to fracturing across property lines,[9] subsurface trespass from transboundary migration of injected wastewater,[10] damage to vertical wells resulting from nearby hydraulic fracturing operations,[11] and impacts of shale exploration on surrounding communities.[12] In recent years, growing concerns about the environment and climate change have animated new debates over the regulation of oil and gas and the use of public lands for mineral development, and have encouraged states and Congress to create incentives such as the 45Q tax credit for lower carbon production techniques such as Carbon Dioxide Enhanced Oil Recovery (CO2-EOR). The application of emergent technologies and rapidly evolving understandings related to the different attributes of unconventional resources raised questions relative to preemption, the application of environmental law statutes, and the proper scope of oil and gas regulation anew.

## II. FEDERAL ONSHORE OIL AND GAS DEVELOPMENT

### § 29:3 Generally

Federal regulation of onshore oil and gas development primarily involves leasing of federal minerals and development activities on federal surface lands, and 710

[4] U.S. v. Midwest Oil Co., 236 U.S. 459, 466–67, 35 S. Ct. 309, 59 L. Ed. 673 (1915).

[5] People's Gas Co. v. Tyner, 131 Ind. 277, 31 N.E. 59 (1892).

[6] Burt, Playing the "Wild Card" in the High-Stakes Game of Urban Drilling: Unconscionability in the Early Barnett Shale Gas Leases, 15 Tex. Wesleyan L. Rev. 1 (2008).

[7] Burt, Playing the "Wild Card" in the High-Stakes Game of Urban Drilling: Unconscionability in the Early Barnett Shale Gas Leases, 15 Tex. Wesleyan L. Rev. 1 (2008).

[8] Wiseman, Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas Production and the Need to Revisit Regulation, 20 Fordham Envtl. L. Rev. 115, 126 (2009).

[9] *See* Briggs v. Southwestern Energy Production Company, 2018 PA Super 79, 184 A.3d 153 (2018), vacated and remanded, 224 A.3d 334 (Pa. 2020).

[10] Environmental Processing Systems, L.C. v. FPL Farming Ltd., 457 S.W.3d 414 (Tex. 2015).

[11] Christiansen, *When the Horizontal and Vertical Collide: Frac Hits and Operator Quest for Détente in the Common Reservoir*, 61 RMMLF-INST 12-1 (2015).

[12] S.B. 19-181, 72d Gen. Assemb., Reg. Sess. (Colo. 2019).

million acres of the federal subsurface estate.[1] This section focuses on and provides a high level overview of the federal leasing process of oil and gas interests.[2] However, the life cycle of onshore oil and gas broadly encompasses development activities generally involving the following phases, which intersect with the other environmental and permitting requirements discussed in this chapter:[3]

- Exploration;[4]
- Seismic and planning operations to identify new oil and natural gas reservoirs (including obtaining site control and safety requirements);[5]
- Construction and drilling operations;
- Ongoing operations and midstream operations involving gathering, treatment, and transportation; and
- Final abandonment and reclamation of the well and location.

Although from a public policy and land management perspective there are differing views on whether to increase domestic energy supply, onshore production from federal lands continues to contribute to domestic production and revenues.[6] The Annual Energy Outlook 2021 prepared by the U.S. Energy Information Administration reports that petroleum remains the most-consumed fuel in the United States, and that amid uncertainty, including the effects of Covid-19 and post-pandemic expectations, the United States continues to be an important global supplier of crude oil and natural gas. The 2021 Outlook predicts such production would continue to grow through 2030 with modest growth through 2051.[7] Separately, based on an April 2021 short-term energy outlook, the U.S. Energy Information Administration projected that U.S. gasoline consumption in 2021 will average 8.6 million barrels per day, up from consumption in 2020 of 8.0 million barrels per day—but down from consumption in 2019 of 9.3 million barrels per day, based on changes and uncertainty surrounding the Covid-19 responses and related energy demand and supply patterns.[8] The U.S. Department of the Interior estimates approximately 5.3 billion barrels of proved oil reserves located on federal onshore acreage and the Energy Information Administration estimates 69 trillion cubic feet of U.S. natural

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**[Section 29:3]**

[1]Brandon S. Tracy, Congressional Research Service, Revenues and Disbursements from Oil and Natural Gas Production on Federal Lands at 1-2 (Sept. 22, 2020) (excluding Native American lands and citing Bureau of Land Management, Public Land Statistics 2019, 2020, Table 1-3, pp. 7-8).

[2]This section does not cover oil and gas development on private lands, which leasing is generally governed under general contract law, and the other state and local regulations discussed in this chapter.

[3]*See generally*, 43 C.F.R. § 3000; BLM Manual MS-3120 (competitive leases), MS-3150 (onshore oil and gas geophysical exploration surface management requirements), MS-3160 (drainage protection manual), MS-3160-9 (communitization), MS-3485 (reports, royalties, and records); BLM Handbook H-3070-2 (economic evaluation of oil and gas properties), H-3100-1 (oil and gas leasing handbook), H-3101-1 (issuance of leases) (H-3109-1 (leasing under special acts) (H-3110-1 (noncompetitive leases), H-3150-1 (onshore oil and gas geophysical exploration surface management requirements), H-3160-5 (inspection and enforcement handbook), H-3160-9 (communitization), H-3203-1 (leasing terms and appendices).

[4]*See, e.g.,* 43 C.F.R. § 3150 (2021).

[5]*See, e.g.*, 43 C.F.R. § 3170 (2021).

[6]*See* Congressional Research Service, U.S. Crude Oil and Natural Gas Production in Federal and Nonfederal Areas (Oct. 23, 2018).

[7]U.S. Energy Information Administration, Annual Energy Outlook 2021 (Feb. 3, 2021) https://www.eia.gov/outlooks/aeo/ (last visited June 16, 2021).

[8]U.S. Energy Information Administration, Short-Term Energy Outlook (April 6, 2021) https://www.eia.gov/outlooks/steo/report/us_oil.php (last visited June 16, 2021).

gas reserves.[9]

In FY2019, crude oil produced on federal lands hit a record value. Domestic production from oil and natural gas from onshore federal lands totaled $4.202 billion payable to the federal government, which represented 86% of total federal revenues from energy and mineral leases on onshore federal lands, including revenues from royalties, bonuses, interest payments, Application for Permit to Drill fees, rents, and other payments.[10] These revenues benefit both federal and state coffers: revenues and disbursements received from onshore oil and gas development revenues, from oil and gas leases under the Mineral Leasing Act, for example, are generally distributed 50% to the states, 40% to the Reclamation Fund, and 10% to the U.S. Treasury.[11] However, revenue disbursements are subject to varying statutory authorities and may fluctuate based on commodity prices, demand, and other factors, which issues are not covered in this section.[12]

## § 29:4 Background

Historically, federal management of oil and gas resources has followed in line with the nation's development, technological advances, and needs. For example, when the General Mining Law was passed in 1872, in the middle of the gold rush, oil and gas or hydrocarbon interests were not a focus of Congress. However, as the country industrialized and the U.S. Navy shifted to oil-powered ships, the focus on federal oil and gas reserves sharpened. Congress initially tried to classify petroleum reserves as locatable placer deposits (i.e., a form of mining claim) under the Oil Placer Act of 1897, but this resulted in an inefficient "race to capture," resulting in physical and economic waste.[1] Accordingly, Congress stepped in and passed the Mineral Leasing Act (MLA) in 1920, which expressly withdrew oil and gas from the availability for mineral location under the 1872 General Mining Law. Not only did Congress act to regulate oil and gas leasing on public lands through passage of the MLA; President Warren Harding issued an executive order on February 27, 1923, setting aside what is now the National Petroleum Reserve in Alaska, as a "Naval Petroleum Reserve" for a minimum of six years for "classification, examination, and preparation of plans for development and until otherwise ordered by Congress or the President."[2]

Today, there are generally three broad categories of minerals on federal lands:

(1) locatable minerals (i.e., hardrock minerals) managed under the General Min-

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[9] *See* Congressional Research Service, U.S. Crude Oil and Natural Gas Production in Federal and Nonfederal Areas at 2-5 (Oct. 23, 2018); U.S. Departments of the Interior, Agriculture, and Energy, Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development (Phase III) Questions and Answers, May 2008, available at https://www.blm.gov/sites/blm.gov/files/EPCA%20Phase%20III%20Questions%20and%20Answers_VR_MF_Final4.pdf.

[10] Brandon S. Tracy, Congressional Research Service, Revenues and Disbursements from Oil and Natural Gas Production on Federal Lands at 1-2 (Sept. 22, 2020) (citing data from the Office of Natural Resources Revenue and excluding revenue from Native American lands).

[11] Brandon S. Tracy, Congressional Research Service, Revenues and Disbursements from Oil and Natural Gas Production on Federal Lands at 10 (Sept. 22, 2020); *see also* U.S. Department of the Interior, Natural Resources Revenue Data, Disbursements by Month, https://revenuedata.doi.gov/downloads/disbursements-by-month/ (last visited June 16, 2021).

[12] For more information on federal revenues and disbursements, *see* Brandon S. Tracy, Congressional Research Service, Revenues and Disbursements from Oil and Natural Gas Production on Federal Lands (Sept. 22, 2020).

**[Section 29:4]**

[1] Act of Feb. 11, 1897, 29 Stat. 526.

[2] President Harding, Exec. Order No. 3797-A (Feb. 27, 1923) (on file with author).

ing Law of 1872,[3] which covers certain valuable mineral deposits such as gold, silver, copper, and gemstones;

(2) leasable minerals as defined by the Mineral Leasing Act of 1920,[4] which include oil and gas, coal, phosphate, potassium, and sodium; and

(3) salable minerals (or "common variety" minerals), such as sand and gravel, which are governed under the Materials Act of 1947.[5]

Federal onshore oil and gas interests are primarily governed under the MLA, and its subsequent amendments.

## § 29:5 BLM Management of Federal Oil and Gas Development

Under the Federal Land Policy and Management Act of 1976 (FLPMA) and the MLA, the Bureau of Land Management (BLM) is the main federal agency tasked with managing energy production and mineral development from federal subsurface lands, including mineral leasing of federal oil and gas mineral interests, and overseeing the exploration, development, and production operations for these resources on federal public lands.[1] As indicated, under the MLA, all federally owned oil, gas, coal, coalbed methane, and oil shale are considered "leasable" minerals.[2] Accordingly, BLM manages onshore oil and gas development under its leasing program and regulations.[3] In addition to leasing, BLM's regulations broadly cover operations associated with the exploration, permitting, development, and production of onshore oil and gas interests on federal leases.[4]

## § 29:6 Federal Land Policy and Management Act of 1976

As a high-level background, FLPMA sets up the statutory authority for the U.S. Department of the Interior and BLM to manage federal lands, including the federal mineral estate, which encompasses onshore oil and gas interests.[1] Specifically, FLPMA provides that the Secretary of the Interior "shall manage the public lands under principles of "multiple use" and "sustained yield" in accordance with land use plans developed by the agency or in accordance with any dedicated specific uses required by such law.[2] The term "multiple use" is broadly defined to mean:

> the management of the public lands and their various resource values so that they are utilized in the combination that will best meet the present and future needs of the American people; making the most judicious use of the land for some or all of these resources or related services over areas large enough to provide sufficient latitude for periodic adjustments in use to conform to changing needs and conditions; the use of

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[3] 30 U.S.C. §§ 21 et seq.

[4] 30 U.S.C. §§ 181 et seq.

[5] 30 U.S.C. §§ 601 et seq.

**[Section 29:5]**

[1] 43 U.S.C. §§ 1701, et seq.

[2] 30 U.S.C. §§ 31 et seq.; *see also* 30 U.S.C. §§ 351 et seq. (extending MLA to acquired lands, or lands obtained from a state or individual by exchange, purchase, or gift in contrast to public domain lands already covered by the MLA, which are lands originally ceded by the original states or foreign sovereigns and have not left federal ownership).

[3] 43 U.S.C. § 1702; 43 C.F.R. § 3160 (2021).

[4] 43 C.F.R. § 3100.0-3 (2021); 43 C.F.R. § 3160 (2021).

**[Section 29:6]**

[1] 43 U.S.C. §§ 1701 et seq.

[2] 43 U.S.C. § 732(a); *see also* BLM, *The Federal Land Policy and Management Act of 1976, as amended,* September 2016, *available at* https://www.blm.gov/sites/blm.gov/files/documents/files/FLPMA2016.pdf.

> some land for less than all of the resources; a combination of balanced and diverse resource uses that takes into account the long-term needs of future generations for renewable and nonrenewable resources, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values; and harmonious and coordinated management of the various resources without permanent impairment of the productivity of the land and the quality of the environment with consideration being given to the relative values of the resources and not necessarily to the combination of uses that will give the greatest economic return or the greatest unit output.[3]

The FLPMA also defines "sustained yield" to mean "the achievement and maintenance in perpetuity of a high-level annual or regular period output of the various renewable resources of public lands consistent with multiple use."[4]

Generally, through the land use planning process required under FLPMA, BLM determines which lands under its management are available for oil and gas leasing including the particular stipulations or conditions of approval applicable to such leases. For example, conditions of approval include consultation with other Federal regulatory agencies under the Endangered Species Act, National Historic Preservation Act, and Clean Water Act, among other statutory requirements. Such leasing decisions are typically analyzed in preparation of a land management plan and environmental impact statement under the National Environmental Policy Act (NEPA), which address cumulative impacts of leasing, exploration, and development. Development of these documents involves collaboration with local, state, and tribal governments, the general public, industry, and other stakeholders on how Federal lands will be used and protected during broader landscape-level approvals and site-specific projects.[5] However, leases may also be reviewed under a programmatic NEPA evaluation of larger project proposals, or a site-specific NEPA analysis for an individual well. As part of this review, land approved for leasing or development takes into consideration BLM's multiple-use purposes both during and after the term of the lease and site-specific mitigation.

Notably, although there are millions of acres of federal public lands, not all public lands are open to mineral development and subject to its multiple use mandate, BLM may also withdraw lands from mineral entry and prohibit new mining and development activities. For example, lands may be withdrawn from mineral entry by the President, executive branch agencies, or Congress subject to valid and existing rights, or Presidential monument designations under the Antiquities Act.[6] To guide oil and gas leasing decisions and to determine which lands are open to oil and gas leasing, BLM field offices prepare comprehensive Resource Management Plans (RMPs).

## § 29:7 Mineral Leasing Act of 1920, and Amendments

Up until 1988, federal onshore oil and gas leasing was governed under a dual leasing system for future oil and gas exploration and development under the MLA. Specifically, the MLA provided that: (1) competitive bidding was required within known geological structures[1] and (2) noncompetitive leases could be issued for areas

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[3] 43 U.S.C. § 1702(c).

[4] 43 U.S.C. § 1702(h).

[5] *See* 43 C.F.R. § 1610 (2021) (BLM's Resource Management Planning regulations).

[6] 16 U.S.C. §§ 431 to 433.

**[Section 29:7]**

[1] "Known geological structures" generally refer to lands within a structure where oil and gas production has been obtained. Originally, the regulations provided that the Director of the Geological Survey would determine the boundaries of known geologic structures of producing oil and gas fields,

not within known geological structures to the first qualified applicants.[2] Because noncompetitive leases had favorable lessee terms, many leases were acquired and lands were held only for speculation without completion of any drilling operations during the primary term. This resulted in a refiling competition at the end of the initial lease term to hold the same lands again. In order to address this result under the existing system, the Department of the Interior established a simultaneous lottery system, in which all interested persons could file an application for a new lease. The Department would draw the winning applicant from the lottery.[3]

## § 29:8 Mineral Leasing Act of 1920, and Amendments—The Federal Onshore Oil and Gas Leasing Reform Act of 1987

The Federal Onshore Oil and Gas Leasing Reform Act of 1987 (FOOGLRA) amended the MLA by instituting a new bidding and leasing system for oil and gas. Specifically, FOOGLRA abolished the simultaneous lottery and dual leasing procedure for known and unknown geological areas, and shifted the leasing program to a competitive bidding system.[1] Under FOOGLRA, the Secretary of the Interior may lease all lands "which are known or believe to contain oil or gas deposits," with the exception of certain wilderness study lands.[2] Such authority, however, does not repeal or change other petroleum development bans (e.g., wilderness or parks),[3] revoke preexisting withdrawals, or necessarily mandate that the Secretary lease any specific areas.

Except for lands within a special tar sand area,[4] under FOOGLRA, federal lands offered for federal oil and gas leasing are leased to the highest responsible qualified bidder in a competitive bidding process at oral auction, held quarterly or according to another interval determined by the Secretary of the Interior, in units up to 2,560 acres (or 5,760 acres in Alaska).[5] A 2014 amendment further authorizes internet-based onshore oil and gas lease sales.[6] If lands are not leased through the competitive bidding process (e.g., no bids are received, tract of land did not receive an adequate bid), such lands are then available for noncompetitive leasing for a period of two years to the first qualified applicant.[7]

Land offered for a lease sale generally come from three sources: (1) lands identified by informal expressions of interest from the public; (2) lands included in offers for noncompetitive leases; or (3) lands identified by BLM. To be a qualified bidder,

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but over time, this responsibility has been transferred to the Minerals Management Service, and now to the BLM. *See* The Story of BLM, BLM Consolidates Its Gains: The 1980s, *available at* https://www.nps.gov/parkhistory/online_books/blm/history/chap5.htm; Establishment of Organizations, 47 Fed. Reg. 4751 (Feb. 2, 1982); Transfer of Responsibility and Authority, 48 Fed. Reg. 8982 (March 2, 1983).

[2] 30 U.S.C. §§ 226(b)(1), 226(c) (amended 1987).

[3] 43 C.F.R. Subpart 3112 (1981); Thor-Westcliffe Development, Inc. v. Udall, 314 F.2d 257, 258 (D.C. Cir. 1963) (upholding agency promulgation of a regulation creating a simultaneous filing and public drawing procedure).

**[Section 29:8]**

[1] 30 U.S.C. §§ 226 et seq.

[2] 30 U.S.C. § 226; 30 U.S.C. § 226-3(a).

[3] 43 C.F.R. § 3100.0-3 (2021).

[4] A "tar sand area" means any consolidated or unconsolidated rock (other than coal, oil shale, or gilsonite) that either: (1) contains a hydrocarbonaceous material with a gas-free viscosity, at original reservoir temperature, greater than 10,000 centipoise, or (2) contains a hydrocarbonaceous material and is produced by mining or quarrying, 30 U.S.C. § 209.

[5] 30 U.S.C. § 226(b)(1)(A).

[6] Pub. L. No. 113-291, div. B, title XXX, § 3022(a), Dec. 19, 2014, 128 Stat. 3762 (codified at 30 U.S.C. § 226(b)(1)(C)).

[7] 30 U.S.C. § 226(c).

BLM regulations require that a party be a citizen of the United States (and cannot be a minor) and that the bidder must comply with: federal acreage limitations; the anti-fraud provisions of FOOGLRA; reclamation requirements; and diligent development of the leases issued to it.[8]

The Secretary is required to accept the highest bid from a responsible qualified bidder, "which is equal to or greater than the national minimum acceptable bid, without evaluation of the value of the lands proposed for lease" and must reject any bids for less.[9] Lease of special tar sand areas are similarly leased to the highest responsible qualified bidder by competitive bidding, but for units of up to 5,760 acres, and the Secretary is authorized to lease additional lands to support any operations necessary for the recovery of tar sands.[10] Following enactment of FOOGLRA, by statute the national minimum acceptable bid was $2 per acre for a period of two years from December 22, 1987 and has remained at this rate since it was set.[11] Under the same provision, the Secretary may increase this minimum upon a finding that such action is necessary "(i) to enhance financial returns to the United States; and (ii) to promote more efficient management of oil and gas resources on Federal lands." Such action is exempt from NEPA. FOOGLRA requires the Secretary to notify the Committee on Natural Resources of the United States House of Representatives and the Committee on Energy and Natural Resources of the United States Senate 90 days prior to making any change in the national minimum accepted bid.[12]

As a lease condition, there is a statutory minimum royalty of 12.5% on the production of oil and gas removed or sold from the lease. While the Secretary has authority to increase the royalty, the Secretary has not done so.[13] Additionally, leases are subject to an annual rental of not less than $1.50 per acre per year for the first five years of the lease term, and not less than $2.00 per acre for each year thereafter.[14] Both competitive and noncompetitive leases are issued for a primary term (i.e. or initial term) of 10 years, provided that each lease shall continue so long as oil and gas is produced in paying quantities (i.e. a habendum clause).[15] If the Secretary suspends lease operations, a lease may be extended for the duration of the suspension.[16] Similar to private leases, the federal leases have codified versions of standard oil and gas savings clauses to extend the duration of the lease in certain circumstances, and the Secretary may extend the lease if production continues.[17] Federal leases may also be included in a pooling, unitization,[18] or communitization

[8] 43 C.F.R. § 3102 (2021).

[9] 43 C.F.R. § 3102 (2021).

[10] 30 U.S.C. § 226(b)(2)(A).

[11] 30 U.S.C. § 226(b)(1)(B).

[12] 30 U.S.C. § 226(b)(1)(B).

[13] 43 C.F.R. § 3103.3-1(a)(1) (2021).

[14] 30 U.S.C. § 226(d). In comparison to private oil and gas lease transactions in which failure to timely pay rentals or other payments can result in automatic termination of the lease, federal oil and gas leases provide lessees a reinstatement route. *See* 30 U.S.C. § 188(c) and (d); 43 U.S.C. § 3108.2-1(b).

[15] 30 U.S.C. § 226(e); *see* 43 C.F.R. § 3160.0-5 (2021) (defining "production in paying quantities" to mean "production from a lease of oil and/or gas of sufficient value to exceed direct operating costs and the cost of lease rentals or minimum royalties").

[16] 30 U.S.C. § 209.

[17] 30 U.S.C. § 226(e); 30 U.S.C. § 226(i) (if a well capable of producing has been completed or production has ceased, the lessee has 60 days to achieve production, or to commence reworking or drilling operations and if such work is completed, the statute provides that the lease shall not terminate).

[18] 43 C.F.R. § 3161.2 (2021). Unitization generally provides for exploration and development of an

agreement,[19] subject to approval by the Secretary.[20]

While FOOGLRA set up a new system for future federal oil and gas leases, it did change the rules applicable to preexisting leases, rights, or law. As a result, any pre-1987 leases are governed under pre-FOOGLRA law as long as the earlier leases continue into their secondary terms from production. However, these provisions will likely become less applicable with the passage of time.

## § 29:9 Mineral Leasing Act of 1920, and Amendments—Regulation of Onshore Oil and Gas Operations

Generally, a federal lease provides the initial authorization to develop oil and gas on federal public lands. However, a lessee also needs to comply with other BLM requirements for exploration or drilling operations. This includes (without limitation) submission of drilling applications, notification requirements (e.g., Sundry Notices), records, reporting, monitoring, measurements and sampling, operator requirements, and permitting either under BLM requirements, or requirements of other agencies. On the flip side, a federal lessee is similarly subject to additional requirements before well abandonment and completion of reclamation.[1] As one example, BLM regulations establish procedures for conducting oil and gas geophysical exploration operations.[2] Likewise, before drilling operations can occur, an operator must obtain an approved application for a permit to drill (APD). An APD must contain a surface plan of operations, and is subject to NEPA review, although APDs for certain exploratory wells may qualify for an EIS categorical exclusion.[3] Requirements related to drilling plans or surface plan of operations required for drilling, and reclamation and bonding requirements, can also depend on the ownership and management of the surface estate, and as a result, become more complicated.

While BLM is the primary mineral management agency over oil and gas leasing, under FOOLGRA there are additional requirements for surface operations, including providing authority to other land management agencies to control surface operations on their lands. Accordingly, where the surface lands over the federal mineral estate are not federally owned or under separate federal management, BLM works with the private surface owner, or other federal agencies to manage the federal mineral estate.[4] If BLM manages the surface estate, operators are subject to BLM regulations governing surface operations. In comparison—and by way of example—

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entire geologic structure or area by a single operator so that drilling and production may proceed in the most efficient and economic manner. BLM, Unitization, Communitization, Spacing, and Drainage, https://www.blm.gov/programs/energy-and-production/oil-and-gas/operations-and-production/unitization-communitization (last visited June 16, 2021).

[19] Communitization provides for the pooling of federal and/or Indian lands, with other lands, when separate tracts under such federal and Indian lands cannot be independently developed and operated in conformity with an established well-spacing program. *See, e.g.,* BLM, Unitization, Communitization, Spacing and Drainage, https://www.blm.gov/programs/energy-and-production/oil-and-gas/operations-and-production/unitization-communitization (last visited June 16, 2021); BLM Handbook, H-3160-9.

[20] 30 U.S.C. § 226(m); 43 C.F.R. § 3161.2 (2021).

**[Section 29:9]**

[1] 43 C.F.R. § 3160 (2021); *see also* BLM, The Gold Book: Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development (2007) available at https://www.blm.gov/sites/blm.gov/files/uploads/The%20Gold%20Book%20-%204th%20Ed%20-%20Revised%202007.pdf. In addition to BLM's regulation generally at 43 C.F.R. § 3160, BLM has also issued Onshore Oil and Gas Orders that supplement its regulations. BLM, Regulations, Onshore Orders and Notices to Lessees, https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/onshore-orders (last visited June 16, 2021), incorporated into BLM's regulations, 43 C.F.R. § 3164 (2021).

[2] *See* 43 C.F.R. § 3150 (2021).

[3] 30 U.S.C. § 226(f); 43 C.F.R. § 3162.3-1(d) (2021).

[4] *See, e.g.,* Mountain States Legal Foundation v. Hodel, 668 F. Supp. 1466, 1470, 18 Envtl. L. Rep.

surface disturbing activities conducted pursuant to a federal oil and gas lease located on National Forest Service lands are subject to Forest Service regulations and could entail additional restrictions or requirements consistent with the relevant forest plan.[5]

As a brief note, while BLM issued regulations to regulate hydraulic fracturing on federal and Indian land in 2015 under the Obama Administration, the BLM rescinded those regulations in their entirety under the Trump Administration in 2017. The decision was upheld by a district court and a Wyoming District Court enjoined BLM's 2015 regulations before they went into effect.[6]

Similarly, BLM's November 18, 2016 final rule concerning, *inter alia*, the waste of Federal and Indian gas through venting, flaring, and leaks (2016 Waste Prevention Rule) that became effective January 17, 2017 was also mostly vacated as discussed below.[7] The intent of the 2016 Waste Prevention Rule was to replace BLM's prior regulation, which generally prohibited venting and flaring of gas produced by oil wells, except when the gas is "unavoidably lost" and when the operator has sought and received BLM's approval to vent or flare.[8] The 2016 Waste Prevention Rule was never fully implemented as a result of administrative and judicial interventions.[9] In particular, industry groups and certain states filed petitions for judicial review in the U.S. District Court for the District of Wyoming, and the court stayed implementation of the rule pending finalization of BLM's voluntary revisions of the rule.[10] BLM issued a final rule revising the 2016 Waste Prevention Rule on September 28, 2018 (2018 Revision Rule).[11] However, a coalition of environmental groups and states then filed a lawsuit challenging the 2018 Waste Prevention Rule and, on July 15, 2020, U.S. District Court for the Northern District of California ordered that the 2018 Revision Rule be vacated.[12] Thereafter, the U.S. District Court for the District of Wyoming lifted the stay challenging the 2016 Waste Prevention Rule, and ultimately found that BLM exceeded its statutory authority and acted arbitrarily in promulgating the 2016 Waste Prevention Rule.[13] As a result, the district court decision vacated the 2016 Waste Prevention Rule, except revisions to: (1) 43 C.F.R. subpart 3178, pertaining to royalty-free use of production; and (2) the amendment of 43 C.F.R. § 3103.3-1, pertaining to royalty rates on competitive leases, which effectively reinstated the Notice to Lessees and Operators of Onshore

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20427 (D. Wyo. 1987).

[5] 43 C.F.R. § 3809.203 (2021); 36 C.F.R. § 228 (2021).

[6] Oil and Gas; Hydraulic Fracturing and Indian Lands, 80 Fed. Reg. 16128, 16128 (Mar. 26, 2015); Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands; Rescission of a 2015 Rule, 82 Fed. Reg. 61924 (Dec. 29, 2017); State v. Bureau of Land Management, 2020 WL 1492708 (N.D. Cal. 2020), State of Wyoming, et al. v. U.S. Dept. of Interior, No. 2:15-cv-00043-SWS (D. Wyo. Sep. 30, 2015); *see also* State of Wyoming v. United States Department of the Interior, 2016 WL 3509415 (D. Wyo. 2016), judgment vacated, appeal dismissed by, 871 F.3d 1133, 85 Env't. Rep. Cas. (BNA) 1300 (10th Cir. 2017).

[7] 81 Fed. Reg. 83008 (Nov. 18, 2016); 82 Fed. Reg. 58050 (Dec. 8, 2017); Wyoming v. United States Department of the Interior, 493 F. Supp. 3d 1046, 1053 (D. Wyo. 2020) (providing history of rule).

[8] 4 Fed. Reg. 76600 (Dec. 27, 1979); Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases (NTL-4A), https://www.blm.gov/sites/blm.gov/files/energy_noticetolessee4a.pdf.

[9] *See, e.g.,* 82 Fed. Reg. 27430 (June 15, 2017).

[10] Wyoming v. Dep't of Int., Case No. 2:16-cv-00285-SWS (D. Wyo.).

[11] 83 Fed. Reg. 49184 (Sept. 28, 2018).

[12] California v. Bernhardt, 472 F. Supp. 3d 573 (N.D. Cal. 2020).

[13] Wyoming v. United States Department of the Interior, 493 F. Supp. 3d 1046, 1056 (D. Wyo. 2020).

Federal and Indian Oil and Gas Leases (NTL-4A).[14] It remains to be seen whether additional regulations will be promulgated under the Biden Administration under either situation.

As indicated above, given the numerous regulations and complexities associated with onshore oil and gas development operations, this section does not comprehensively cover oil and gas exploration, drilling, development, and production operations. Nevertheless, it is intended to provide a high-level overview and introduction to the field.

## § 29:10 FOOGLRA Anti-Fraud Provisions

In addition to setting up a new leasing procedure, FOOGLRA additionally enacted anti-fraud provisions to address fraud allegedly occurring under the prior provisions of the MLA.[1] Accordingly, it is now criminal to: (1) "organize or participate in any scheme, arrangement, plan, or agreement to circumvent or defeat the provisions of [the MLA] or its implementing regulations"; or (2) "to seek to obtain or to obtain any money or property by means of false statements of material facts or by failing to state material facts concerning": (a) the value of any lease or portion thereof issued or to be issued; (b) the availability of any land for leasing; (c) the ability of any person to obtain leases; or (d) violation of any regulation implementing FOOGLRA.[2]

A person that knowingly violates these provisions is subject to up to a $500,000 fine and five years' imprisonment, or both.[3] The U.S. Attorney General may also institute a civil action "for a temporary restraining order, injunction, civil penalty of not more than $100,000 for each violation, or other appropriate remedy, including but not limited to, a prohibition from participation in exploration, leasing, or development of any Federal mineral" for any violation under FOOGLRA.[4] In both a criminal and civil action, the provisions broadly apply not only to the corporation or other entity, but also to any officer, employee, or agent of the corporation or entity who knowingly authorized, ordered, or carried out the violation—unless it is shown the officer, employee, or agent, was acting without the knowledge or consent of the corporation or entity.[5] There are similar provisions for a state to commence a civil action conducting activity within the state that violates this section after notice to the U.S. Attorney General.[6]

## § 29:11 BLM Enforcement Provisions

Separate from the anti-fraud provisions, BLM has further authority to bring enforcement actions and impose penalties against oil and gas lessees for any

[14] Wyoming v. United States Department of the Interior, 493 F. Supp. 3d 1046, 1087, 1056 (D. Wyo. 2020).

**[Section 29:10]**

[1] *See* Thomas L. Sansonetti and William R. Murray, *A Primer on the Federal Onshore Oil and Gas Leasing Reform Act of 1987 and Its Regulations*, Land & Water Law Review: Vol. 25: Iss. 2 (1990), pp. 375-416 *available at* https://scholarship.law.uwyo.edu/land_water/vol25/iss2/6; Patricia J. Beneke, *The Federal Onshore Oil and Gas Leasing Reform Act of 1987: A Legislative History and Analysis*, Journal of Natural Resources & Environmental Law: Vol. 4: Iss. 1, Article 3 (1988) *available at* https://uknowledge.uky.edu/jnrel/vol4/iss1/3.

[2] 30 U.S.C. § 195(a).

[3] 30 U.S.C. § 195(b).

[4] 30 U.S.C. § 195(c).

[5] 30 U.S.C. § 195(d).

[6] *See* 30 U.S.C. § 195(f).

noncompliance with BLM's regulations.[1] Under these provisions, major violations carry a potential penalty of $1,000 per violation, per inspection, whereas minor violations could result in a penalty of $250 per violation, per inspection.[2] Similar to other environmental protection statutes, in circumstances where operations could result in immediate, substantial, and adverse impacts on public health, and safety, the environment, production accountability, or royalty income, the agency may shut down operations.[3] Noncompliance can also result in BLM actions to remedy the noncompliance at the operator's cost, and in some cases, cancellation and termination of the lease.

## § 29:12 Leasing Under Special Acts—National Petroleum Reserve in Alaska

The Naval Petroleum Reserves Production Act of 1976, as amended (NPRPA),[1] authorizes oil and gas leasing in the National Petroleum Reserve in Alaska (NPR-A). NPR-A encompasses approximately 23 million area acres on Alaska's North Slope, and significantly contributes to BLM's 25 million areas of federally managed mineral estate. As of 2019, NPR-A oil and gas lease revenue amounted to more than $56 million.[2] The area was first designated by President Warren G. Harding as an area for emergency oil supply for the U.S. Navy under a 1923 executive order. Management of the reserve was then transferred, under the NPRPA, from the Secretary of the Navy to the Secretary of the Interior and BLM. Under the NPRPA, as amended, BLM is directed to carry out "an expeditious program of competitive leasing of oil and gas in the Reserve."[3] Nevertheless, oil and gas leasing in the NPR-A should also be conducted in order to protect the surface values of the River, the Teshekpuk Lake areas, and other areas designated by the Secretary of the Interior as containing any significant subsistence, recreational, fish and wildlife, or historical or scenic value.[4]

Instead of being governed by the MLA and related implementing regulations, regulations for NPR-A oil and gas leasing, exploration and operations are separately set forth under 43 C.F.R. Parts 3130, 3150, and 3160. Generally, the NPRPA establishes a competitive leasing system with a bidding system based on bidding systems in the Outer Continental Shelf Lands Act Amendments of 1978.[5] In comparison to MLA leases, leases may be up to 60,000 acres, and leases are issued for an initial period not to exceed 10 years, but may be extended for "so long thereafter as oil or gas is produced from the lease in paying quantities, oil or gas is capable of being produced in paying quantities, or drilling or reworking operations, as approved by the Secretary, are conducted on the leased land."[6] A lease may also

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**[Section 29:11]**

[1] 43 C.F.R. § 3163 (2021).

[2] 43 C.F.R. § 3163.1 (2021).

[3] 43 C.F.R. § 3163.1(a)(3) (2021).

**[Section 29:12]**

[1] 42 U.S.C. §§ 6501 et seq.

[2] BLM, National Petroleum Reserve in Alaska, https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/about/alaska/NPR-A.

[3] 32 U.S.C. § 6506a.

[4] 42 U.S.C. § 6504; President Harding, Exec. Order No. 3797-A (Feb. 27, 1923) (on file with author).

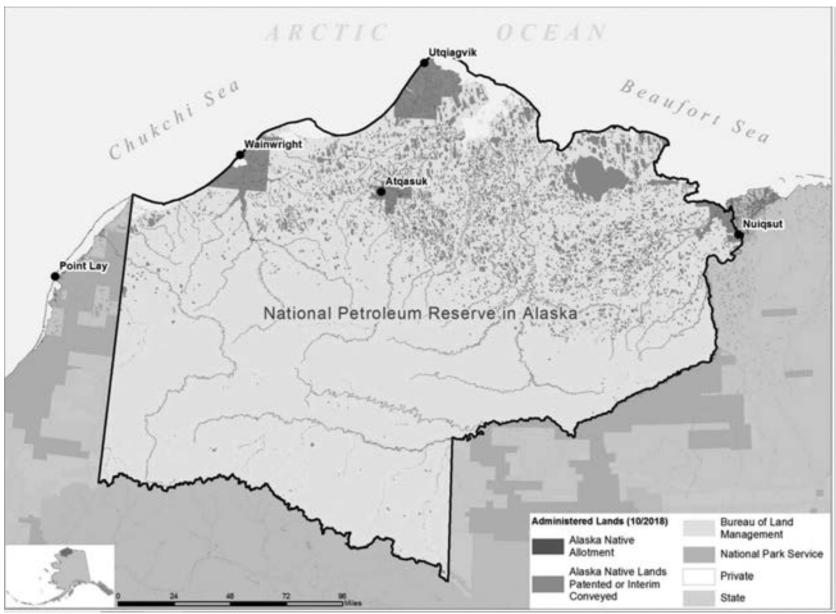
[5] 42 U.S.C. § 6506a.

[6] 42 U.S.C. § 6506a(i)(1).

be renewed for another 10-year period if certain terms and conditions are met.[7] Similar to MLA leases, NPRPA leases may also be included in units, pools, or other joint development agreements, if the Secretary determines the action is in the public interest.[8]

Drilling within the NPR-A has been controversial, to say the least. In more recent times, the Trump Administration took action to expand leasing and development in the NPR-A; on June 26, 2020, BLM released a plan to allow leasing on approximately 18.7 million more acres of land (approximately 82% of the NPR-A).[9] However, the Biden Administration temporarily suspended all onshore oil and gas leasing, including in the NPR-A for 60 days. It remains to be seen what, if any, further action the Biden Administration will take.[10]

Map of NPR-A[11]




## § 29:13 Right of Way Leasing Act of 1930

A series of decisions rendered at the turn of the 20th century questioned whether or not a federal oil and gas lease could cover lands within a federal right-of-way, particularly rights-of-way previously granted to the railroads.[1] Congress, in re-

[7] 42 U.S.C. § 6506a(i)(2), (3).

[8] 42 U.S.C. § 6506a(j).

[9] National Petroleum Reserve in Alaska, Integrated Activity Plan Record of Decision (Dec. 2020).

[10] Executive Order No. 3395, Temporary Suspension of Delegated Authority, available at https://www.doi.gov/sites/doi.gov/files/elips/documents/so-3395-signed.pdf.

[11] BLM, https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/about/alaska/NPR-A.

**[Section 29:13]**

[1] *See, e.g.,* Northern Pac. Ry. Co. v. Townsend, 190 U.S. 267, 271-72, 23 S. Ct. 671, 47 L. Ed. 1044 (1903); Rio Grande Western Ry. Co. v. Stringham, 239 U.S. 44, 47, 36 S. Ct. 5, 60 L. Ed. 136 (1915); Windsor Reservoir & Canal Co. v. Miller, 51 L.D. 27, 34 (1925); *compare* Great Northern R. Co. v. U.S., 315 U.S. 262, 279, 62 S. Ct. 529, 86 L. Ed. 836 (1942); Solicitor Opinion, 67 Pub. Lands Dec. 225 (1960) (clarifying the property interest under certain right-of-way statutes is an easement rather than a limited fee interest).

sponse, passed the Act of May 21, 1930 (the "Right-of-Way Leasing Act").[2] Under the Right-of-Way Leasing Act, the Secretary of the Interior is authorized to "lease deposits of oil and gas in or under lands embraced in railroad or other rights of way acquired under any law of the United States, whether the same be a base fee or mere easement; Provided, That, . . . no lease shall be executed hereunder except to the . . . [owner] by whom such right of way was acquired, or to the lawful successor, assignee, or transferee of such [owner]."[3] The original regulations mimicked the statutory language until the Department of the Interior amended the provisions in 1983, presumably to align with caselaw, to state:

> This authority shall be exercised *only with respect to railroad rights-of-way* and easements issued pursuant either to the Act of March 3, 1875 (43 U.S.C. 934 *et seq.*), or pursuant to earlier railroad right-of-way statutes, and with respect to rights-of-way and easements issued pursuant to the Act of March 3, 1891 (43 U.S.C. 946 *et seq.*). The oil and gas underlying any other right-of-way or easement is included within any oil and gas lease issued pursuant to the Act which covers the lands within the right-of-way, subject to the limitations on use of the surface, if any, set out in the statute under which, or permit by which, the right-of-way or easement was issued, and such oil and gas shall not be leased under the Act of May 21, 1930.[4]

Although the amended regulation may conflict with the statutory provisions authorizing the right to lease "other rights of way acquired under any law of the United States," this issue has largely been unchallenged in recent years. In any event, the Right-of-Way Leasing Act and its implementing regulations set forth a process for an owner of the right-of-way to apply for an oil and gas lease or assign its rights to apply for the lease to a third party, by submitting an application that details "the facts as to the ownership of the right-of-way, and of the transfer if the application is filed by a transferee; the development of oil or gas in adjacent or nearby lands, the location and depth of the wells, the production and the probability of drainage of the deposits in the right-of-way."[5] After BLM review and determination that a lease of the right-of-way is consistent with the public interest, notice is provided to the owner or lessee of the oil and gas in the adjoining lands, and such owner or lessee is provided an opportunity to submit a bid for a lease during the same timeframe as a third party lease applicant.[6] Leases are awarded to the bidder whose offer is determined to be to the best advantage of the United States, considering the amount of royalty to be received and the better development under the respective means of production and operation. The lease is issued for a term no longer than 20 years.[7]

## § 29:14 Leasing of National Park System Units

Certain units with the National Park System shown on maps identified in 36 C.F.R. § 3109.2 may be leased for oil and gas development subject to BLM's regulations under 43 C.F.R. Group 3100 and Parts 3160 and 3180.[1] Any lease or permit requires consent of the Regional Director of the National Park Service before issu-

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[2] 30 U.S.C. §§ 301 to 306.

[3] 30 U.S.C. § 301.

[4] 43 C.F.R. § 3109.1-1 (2021) (emphasis added).

[5] 43 C.F.R. § 3109.1-2 (2021).

[6] 43 C.F.R. §§ 3109.1-2, 3109.1-4 (2021).

[7] 43 C.F.R. §§ 3109.1-4, 3109.1-5 (2021).

**[Section 29:14]**

[1] 43 C.F.R. § 3109.2; *see also* U.S. Department of the Interior Department Manual, 516 DM 12.3, available at: https://www.doi.gov/sites/doi.gov/files/elips/documents/chapte1_16.doc.

ance or renewal.[2] Additionally, such consent shall only be granted "upon a determination by the Regional Director that the activity permitted under the lease or permit will not have significant adverse effect upon the resources or administration of the unit pursuant to the authorizing legislation of the unit."[3] The Regional Director can also include conditions "to protect the surface and significant resources of the unit, to preserve their use for public recreation, and to the condition that site specific approval of any activity on the lease will only be given upon concurrence by the Regional Director."[4] Despite this authorization, the National Park Service 2006 Management Policies, which are still in effect, provide that all National Park Service units are closed to new federal mineral leasing, with the exceptions of the Glen Canyon, Lake Mead, and Whiskeytown-Shasta-Trinity national recreation areas.[5]

### § 29:15 Mining and Minerals Policy of 1970

As an additional overlay to onshore oil and gas development, Congress passed the Mining and Minerals Policy Act of 1970. This statute declares that it is the continuing policy of the Federal Government, and in the national interest, "to foster and encourage private enterprise in

(1) the development of economically sound and stable domestic mining, minerals, metal and mineral reclamation industries,
(2) the orderly and economic development of domestic mineral resources, reserves, and reclamation of metals and minerals to help assure satisfaction of industrial, security and environmental needs,
(3) mining, mineral, and metallurgical research, including the use and recycling of scrap to promote the wise and efficient use of our natural and reclaimable mineral resources, and
(4) the study and development of methods for the disposal, control, and reclamation of mineral waste products, and the reclamation of mined land, so as to lessen any adverse impact of mineral extraction and processing upon the physical environment that may result from mining or mineral activities."[1]

The term "minerals" is broadly defined to include all minerals and mineral fuels including oil, gas, coal, oil shale, and uranium.[2] While the statute does not specify certain procedures outside of the policy goals above, the statute expressly provides that it "shall be the responsibility of the Secretary of the Interior to carry out this policy" when carrying out other related programs.[3]

Notably, the Mining and Minerals Policy Act was passed in response to the 1970s energy crisis, but this policy continues to add to the tension behind domestic oil and gas exploration, development, and production.

## III. FEDERAL OUTER CONTINENTAL SHELF DEVELOPMENT

### § 29:16 The Outer Continental Shelf Lands Act

[2] 43 C.F.R. § 3109.2(b) (2021).

[3] 43 C.F.R. § 3109.2(b) (2021).

[4] 43 C.F.R. § 3109.2(b) (2021).

[5] National Park Service, Management Policies 2006, at 118 (Section 8.7.2) available at https://www.nps.gov/policy/MP_2006.pdf.

**[Section 29:15]**

[1] 30 U.S.C. § 21a.

[2] 30 U.S.C. § 21a.

[3] 30 U.S.C. § 21a.

Congress enacted the Outer Continental Shelf Lands Act (OCSLA)[1] in 1953 to authorize the Secretary of the Interior to administer the exploration, development, and production of minerals of the outer Continental Shelf (OCS). Over time, the Act has evolved far from its original "carte blanche delegation of authority"[2] to the Secretary of the Interior into a comprehensive, step-by-step process for issuing minerals leases in the OCS. Despite this overhaul, the basic purpose of OCSLA remains the same, and the statute achieves this purpose in two ways: (1) by establishing the jurisdiction of the United States over the OCS; and (2) by providing the framework by which the federal government opens up the OCS for resource development. This chapter provides a historical background of OCSLA, describes the current implementation of its statutory directives, and highlights some recent developments in caselaw and executive action under OCSLA.

## § 29:17 The History and Evolution of OCSLA

On September 28, 1945, in an effort to advance conservative and prudent offshore resource development, President Harry Truman issued a proclamation declaring that "the natural resources of the subsoil and sea bed [sic] of the continental shelf beneath the high seas but contiguous to the coasts of the United States" were subject to federal jurisdiction and control.[1] Jurisdictional disputes between coastal states and the federal government quickly followed, which culminated in a series of United States Supreme Court decisions holding that the federal government has exclusive jurisdiction over the entire continental shelf because it has "paramount" rights in ocean waters and submerged lands below the low water mark.[2] In effect, the Supreme Court ruled that coastal states had no title to submerged lands off of their respective coasts.[3]

In response to the U.S. Supreme Court decisions and to resolve the issue of federal-state control, Congress passed the Submerged Lands Act (SLA)[4] and OCSLA in 1953.[5] SLA gave coastal states exclusive jurisdiction over the submerged lands within three nautical miles offshore.[6] OCSLA affirmed the United States' exclusive jurisdiction lying seaward of state coastal waters and also established general directives for the Secretary in managing and leasing the OCS.[7]

Initially, OCSLA "provided essentially an open-ended grant of authority to the Secretary of the Interior to proceed with leasing on the outer Continental Shelf."[8] This broad discretion was due to an expectation that offshore production, a new and unproven technology, would only act as a small supplement to production from

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**[Section 29:16]**

[1] 43 U.S.C. §§ 1331 to 1356b.

[2] H.R. REP. NO. 590, 95th Cong., 1st Sess. 74 (1977), reprinted in 1978 U.S.C.C.A.N. 1450, 1461 [hereinafter H.R. REP. NO. 590].

**[Section 29:17]**

[1] Proclamation No. 2667, 10 Fed. Reg. 12303 (1945).

[2] *See* U.S. v. State of Cal., 332 U.S. 19, 38–39, 67 S. Ct. 1658, 91 L. Ed. 1889, 1947 A.M.C. 1579 (1947), opinion supplemented, 332 U.S. 804, 68 S. Ct. 20, 92 L. Ed. 382 (1947); U.S. v. State of La., 339 U.S. 699, 705, 70 S. Ct. 914, 94 L. Ed. 1216 (1950), judgment entered, 340 U.S. 899, 71 S. Ct. 275, 95 L. Ed. 651 (1950); U.S. v. State of Tex., 339 U.S. 707, 717–718, 70 S. Ct. 918, 94 L. Ed. 1221 (1950).

[3] H.R. REP. NO. 590, reprinted in 1978 U.S.CC.A.N. at 1463.

[4] 43 U.S.C. §§ 1301 et seq.

[5] H.R. REP. NO. 590, reprinted in 1978 U.S.C.C.A.N. at 1464.

[6] 43 U.S.C. § 1312.

[7] H.R. REP. NO. 590, reprinted in 1978 U.S.CC.A.N. at 1464.

[8] H.R. REP. NO. 590, reprinted in 1978 U.S.C.C.A.N. at 1509.

onshore fields.[9] Following passage of OCSLA and up until the late 1960s, the OCS leasing process proceeded at a relatively small scale and was subject to little national scrutiny.[10] However, in 1969, a major blowout from an OCS drilling project in the Santa Barbara Channel caused what was the largest oil spill in United States history, prompting concerns about the environmental impacts of OCS operations.[11] The decline of domestic energy production and the Arab oil embargo of 1973 also led to the rapid acceleration of OCS development, in an effort to reduce dependence on foreign energy supplies.[12] This shift in national attention, coupled with new issues regarding the role of state and local governments in OCS leasing and management, culminated in growing concern over the direction of the OCS process under OCSLA.[13]

Congress sought to remedy these concerns with the OCSLA Amendments of 1978.[14] These amendments were comprehensive and designed to provide a new statutory regime for OCS resource management, expedite the development of the OCS, and enhance environmental protections.[15] While OCSLA has since been amended, the statute following the 1978 amendments has not been fundamentally changed, and those amendments remain the framework for current OCS leasing and management.

### § 29:18 Federal Jurisdiction under OCSLA, Applicability of Laws of Adjacent States, and Aboriginal Rights in the OCS

OCSLA extends exclusive federal jurisdiction to the subsoil and seabed of the OCS,[1] which is defined to include all submerged lands beyond state coastal waters but within the limits of U.S. jurisdiction (200 nautical miles offshore as established by the Exclusive Economic Zone of the United States).[2] Further, within the OCS, exclusive federal jurisdiction applies to all: (1) artificial islands; (2) installations and other devices permanently or temporarily attached to the seabed, which may be erected to explore, develop, or produce resources; and (3) installations or devices (other than a ship or vessel) used to transport resources.[3]

OCSLA also establishes that civil and criminal laws of adjacent states, "to the extent that they are applicable and not inconsistent" with federal law, are declared as surrogate federal law for the OCS.[4] Determining when state law stands in as surrogate federal law has been contentious and was recently addressed by the United States Supreme Court in *Parker Drilling Management Services, Ltd. v. Newton*.[5] In *Parker Drilling Management Services, Ltd.*, the plaintiff was an OCS drilling platform employee who had claimed that the defendant, his employer, had violated

[9]H.R. REP. NO. 590, reprinted in 1978 U.S.C.C.A.N. at 1509.

[10]H.R. REP. NO. 590, reprinted in 1978 U.S.C.C.A.N. at 1481.

[11]H.R. REP. NO. 590, reprinted in 1978 U.S.C.C.A.N. at 1484, 1496.

[12]H.R. REP. NO. 590, reprinted in 1978 U.S.C.C.A.N. at 1496.

[13]H.R. REP. NO. 590, reprinted in 1978 U.S.C.C.A.N. at 1497 to 1501.

[14]H.R. REP. NO. 590, reprinted in 1978 U.S.C.C.A.N. at 1507 to 08.

[15]H.R. REP. NO. 590, reprinted in 1978 U.S.C.C.A.N. at 1460.

**[Section 29:18]**

[1]43 U.S.C. § 1332(1).

[2]43 U.S.C. § 1331(a); *see* Proclamation No. 5030, 48 Fed. Reg. 10605 (March 10, 1983) (establishing Exclusive Economic Zone of the United States).

[3]43 U.S.C. § 1333(a)(1).

[4]43 U.S.C. § 1333(a)(2)(A).

[5]Parker Drilling Management Services, Ltd. v. Newton, 139 S. Ct. 1881, 204 L. Ed. 2d 165, 2019 Wage & Hour Cas. 2d (BNA) 212765, 169 Lab. Cas. (CCH) P 36713, 2019 A.M.C. 1548 (2019).

California minimum wage and overtime laws.[6] The parties agreed that OCSLA applied to the drilling platforms but disagreed on whether relevant California law could stand in as surrogate federal law under the statute.[7] The district court, relying on Fifth Circuit precedent that held state law only stands in to the extent necessary to "fill a significant void or gap" in federal law,[8] found that California law was inapplicable because the Fair Labor Standards Act of 1938[9] (FLSA) comprehensively addressed the issue.[10] On appeal, the Ninth Circuit rejected this approach, holding that a gap in federal law was not required to apply state law under OCSLA.[11] Acknowledging the resulting circuit split, the Supreme Court granted certiorari.[12]

The Supreme Court held similarly to the Fifth Circuit and found that "state laws can be 'applicable and not inconsistent' with federal law . . . only if federal law does not address the relevant issue."[13] The Supreme Court found this interpretation supported by the context of OCSLA, which provides for exclusive federal jurisdiction of the OCS rather than overlapping state and federal jurisdiction.[14] The Supreme Court further justified its interpretation by reasoning that allowing adjacent state law to govern the OCS would make much of OCSLA unnecessary,[15] that the interpretation is consistent with the federal-enclave model embodied by OCSLA,[16] and that the interpretation aligns with past Supreme Court precedent.[17]

Ultimately, the Supreme Court held that the FLSA, rather than California law, applied and therefore declined to address the question of what would constitute a gap in federal law that would allow state law to stand in as surrogate federal law.[18] Thus while *Parker Drilling Management Services, Ltd.* provides a degree of clarity as to when the laws of states adjacent to the OCS apply, it is anticipated that this jurisdictional issue will continue to be litigated moving forward.

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[6]Parker Drilling Management Services, Ltd. v. Newton, 139 S. Ct. 1881, 1886, 204 L. Ed. 2d 165, 2019 Wage & Hour Cas. 2d (BNA) 212765, 169 Lab. Cas. (CCH) P 36713, 2019 A.M.C. 1548 (2019).

[7]Parker Drilling Management Services, Ltd. v. Newton, 139 S. Ct. 1881, 204 L. Ed. 2d 165, 2019 Wage & Hour Cas. 2d (BNA) 212765, 169 Lab. Cas. (CCH) P 36713, 2019 A.M.C. 1548 (2019).

[8]Continental Oil Co. v. London Steam-Ship Owners' Mut. Ins. Ass'n, 417 F.2d 1030, 1036, 1969 A.M.C. 1882 (5th Cir. 1969).

[9]29 U.S.C. §§ 201 et seq.

[10]*Parker Drilling Mgmt. Servs.*, Ltd., 139 S. Ct. at 1886.

[11]Newton v. Parker Drilling Management Services, Ltd., 881 F.3d 1078, 1081-82, 27 Wage & Hour Cas. 2d (BNA) 1061, 168 Lab. Cas. (CCH) P 61840, 2018 A.M.C. 1030 (9th Cir. 2018), opinion amended on denial of reh'g en banc, 888 F.3d 1085 (9th Cir. 2018), vacated and remanded, 139 S. Ct. 1881, 204 L. Ed. 2d 165, 2019 Wage & Hour Cas. 2d (BNA) 212765, 169 Lab. Cas. (CCH) P 36713, 2019 A.M.C. 1548 (2019) and cert. granted, 139 S. Ct. 914, 202 L. Ed. 2d 641 (2019) and vacated and remanded, 139 S. Ct. 1881, 204 L. Ed. 2d 165, 2019 Wage & Hour Cas. 2d (BNA) 212765, 169 Lab. Cas. (CCH) P 36713, 2019 A.M.C. 1548 (2019).

[12]*Parker Drilling Mgmt. Servs., Ltd.*, 139 S. Ct. at 1886–87.

[13]*Parker Drilling Mgmt. Servs., Ltd.*, 139 S. Ct. at 1889.

[14]*Parker Drilling Mgmt. Servs., Ltd.*, 139 S. Ct. at 1889.

[15]*Parker Drilling Mgmt. Servs., Ltd.*, 139 S. Ct. at 1889–90.

[16]*Parker Drilling Mgmt. Servs., Ltd.*, 139 S. Ct. at 1890. As the Supreme Court explained, when an area in a state becomes a federal enclave, only the state law in effect at the time jurisdiction transfers continues in force and only if it does not conflict with federal policy. *Parker Drilling Mgmt. Servs., Ltd.*, 139 S. Ct. at 1890. Further, state law does not presumptively apply to the federal enclave. *Parker Drilling Mgmt. Servs., Ltd.*, 139 S. Ct. at 1890. Originally, the OCSLA treated the OCS as a federal enclave, and therefore the statute suggests that state law does not apply to the OCS where federal law is on point. *Parker Drilling Mgmt. Servs., Ltd.*, 139 S. Ct. at 1890–91.

[17]*Parker Drilling Mgmt. Servs., Ltd.*, 139 S. Ct. at 1891-92; *see* Rodrigue v. Aetna Cas. & Sur. Co., 395 U.S. 352, 357-58, 89 S. Ct. 1835, 23 L. Ed. 2d 360, 1969 A.M.C. 1082 (1969) (interpreting the OCSLA to grant exclusive federal jurisdiction on the OCS, with state law able to be used to "fill federal voids").

[18]*Parker Drilling Mgmt. Servs., Ltd.*, 139 S. Ct. at 1893.

Another issue that has remains unsettled in the courts is whether Alaska Natives retain aboriginal title in the OCS. The concept of aboriginal title, which extends to the right to fish and hunt on aboriginal lands and waters, originates from early United States Supreme Court precedent concerning the relationship between the federal government and Indigenous tribes.[19] In Alaska, two federal statutes have significantly shaped the aboriginal rights of Indigenous tribes. The Alaska Native Claims Settlement Act (ANCSA)[20] extinguished aboriginal land claims to federal and state lands and resources and state waters, including any hunting or fishing rights.[21] In exchange, ANCSA created Native-owned corporations;[22] conveyed roughly 45 million acres of select land to the Native corporations;[23] and created the Alaska Native Fund, into which the federal and state government deposited $962.5 million to be distributed among the Native corporations.[24] To ensure that Alaska Native rights to natural resources used for subsistence were protected, Congress later passed the Alaska National Interest Lands Conservation Act (ANILCA).[25] ANILCA set aside over 100 million acres of land in Alaska as conservation system units, which included national parks, wildlife refuges, forests, and monuments,[26] and addressed the protection of rural Alaska residents' subsistence rights under Title VIII of the Act.[27] The scope of these statutes, and how they affect aboriginal rights of Alaska Natives in the OCS, have been subject to extended litigation over the past few decades.

In *Amoco Production Co. v. Village of Gambell* (*Gambell II*),[28] the Alaska Native villages of Gambell and Stebbins brought suit to enjoin the Department of the Interior from proceeding with an OCS lease sale, claiming that it would adversely affect their aboriginal hunting and fishing rights on the OCS and that the Secretary had failed to comply with Title VIII of ANILCA.[29] The United States Supreme Court overturned the Ninth Circuit in finding that Title VIII of ANILCA does not apply to the OCS, as the statute only applies to public lands situated within Alaska.[30] Following vacatur and remand of the case, a subsequent appeal of the lawsuit to the Ninth Circuit applied the same statutory analysis to the scope of extinguished aboriginal rights under ANCSA in *People of Village of Gambell v. Hodel* (*Gambell III*).[31] In *Gambell III*, the Ninth Circuit held that ANCSA only extinguished claims within the boundaries of Alaska and not the OCS.[32] The Ninth Circuit also acknowledged that aboriginal rights may exist in the OCS concurrently with and

[19]*See* Johnson v. M'Intosh, 21 U.S. 543, 5 L. Ed. 681, 1823 WL 2465 (1823); *see also* Rights and Roles: Alaska Natives and Ocean and Coastal Subsistence Resources, 8 Fla. A & M U. L. Rev. 219, 223 (2013) (discussing the history of aboriginal rights).

[20]43 U.S.C. §§ 1601 et seq.

[21]43 U.S.C. § 1603(b).

[22]43 U.S.C. §§ 1606, 1607.

[23]43 U.S.C. §§ 1610 to 13.

[24]43 U.S.C. § 1605.

[25]16 U.S.C. §§ 3101 to 3103.

[26]Alaska Department of Fish and Game, *Alaska National Interest Lands Conservation Act (ANILCA) Program*, available at https://www.adfg.alaska.gov/index.cfm?adfg=habitatoversight.anilca.

[27]16 U.S.C. §§ 3111 to 3126.

[28]Amoco Production Co. v. Village of Gambell, AK, 480 U.S. 531, 107 S. Ct. 1396, 94 L. Ed. 2d 542, 17 Envtl. L. Rep. 20574 (1987).

[29]Amoco Production Co. v. Village of Gambell, AK, 480 U.S. 531, 535, 107 S. Ct. 1396, 94 L. Ed. 2d 542, 17 Envtl. L. Rep. 20574 (1987).

[30]Amoco Production Co. v. Village of Gambell, AK, 480 U.S. 531, 546–552, 107 S. Ct. 1396, 94 L. Ed. 2d 542, 17 Envtl. L. Rep. 20574 (1987).

[31]People of Village of Gambell v. Hodel, 869 F.2d 1273, 19 Envtl. L. Rep. 21150 (9th Cir. 1989).

[32]People of Village of Gambell v. Hodel, 869 F.2d 1273, 1280, 19 Envtl. L. Rep. 21150 (9th Cir.

despite the recognized paramount rights of the federal government in the OCS,[33] but left it to the district court on remand to determine whether the Alaska Native villages in fact possessed aboriginal rights in the OCS and whether OCSLA extinguishes subsistence rights in the OCS as a matter of law.[34] These issues were ultimately never addressed, however, as the district court granted summary judgment to the federal government because the plaintiffs did not produce enough evidence to support their claim that drilling and other activities would interfere with their exercise of aboriginal rights.[35]

While the Ninth Circuit later clarified that Alaska Native villages do not retain exclusive rights to use or occupy the OCS based on aboriginal rights given the paramount rights of the federal government,[36] there still remains the possibility that non-exclusive aboriginal rights exist in the OCS. Recent efforts to establish these rights have required plaintiff villages to meet a high burden of providing sufficient evidence to demonstrate aboriginal title in federal waters and seabed,[37] and it remains to be seen to what extent aboriginal rights coincide with the exclusive federal jurisdiction in the OCS, particularly in the context of OCSLA.

## § 29:19 Regulatory Authority Under OCSLA

Responsibility over the regulatory regime established by OCSLA was originally designated to the former Minerals Management Service (MMS).[1] However, in 2010 the Secretary of the Interior reorganized MMS to improve management, oversight, and accountability of OCS activities.[2] This resulted in the creation of three separate administrative agencies: the Office of Natural Resources Revenue (ONRR), the Bureau of Safety and Environmental Enforcement (BSEE), and the Bureau of Ocean Energy Management (BOEM).[3]

## § 29:20 The Office of Natural Resources Revenue

Established within the Office of the Assistant Secretary for Policy, Management

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1989).

[33] People of Village of Gambell v. Hodel, 869 F.2d 1273, 1277, 19 Envtl. L. Rep. 21150 (9th Cir. 1989); *see also supra* n. 4 and accompanying text (referencing paramountcy cases).

[34] *Gambell III*, 869 F.2d at 1280.

[35] *See* People of Village of Gambell v. Babbitt, 999 F.2d 403, 405 (9th Cir. 1993) (discussing district court decision and finding no remaining basis for federal jurisdiction in the case).

[36] Native Village of Eyak v. Trawler Diane Marie, Inc., 154 F.3d 1090, 1097, 1999 A.M.C. 595, 29 Envtl. L. Rep. 20016 (9th Cir. 1998).

[37] *See* Native Village of Eyak v. Blank, 688 F.3d 619, 626 (9th Cir. 2012) (affirming district court's findings that plaintiff villages did not produce sufficient evidence of use and occupancy in OCS to establish entitlement to non-exclusive aboriginal rights).

**[Section 29:19]**

[1] *The Reorganization of the Former MMS*, BUREAU OF OCEAN ENERGY MGMT., http://www.boem.gov/Reorganization/ (last visited June 16, 2021).

[2] *The Reorganization of the Former MMS*, BUREAU OF OCEAN ENERGY MGMT., http://www.boem.gov/Reorganization/ (last visited June 16, 2021). While management shortcomings of MMS were perceived by both the Department of the Interior and Congress beforehand, the April 20, 2010 oil spill from the Deepwater Horizon drilling rig primarily spurred the MMS reorganization. *See Reorganization of the Minerals Management Service in the Aftermath of the Deepwater Horizon Oil Spill*, Congressional Research Service (Nov. 10, 2010), at 1-3, *available at* https://fas.org/sgp/crs/misc/R41485.pdf.

[3] *The Reorganization of the Former MMS*, BUREAU OF OCEAN ENERGY MGMT., http://www.boem.gov/Reorganization/ (last visited June 16, 2021). While management shortcomings of MMS were perceived by both the Department of the Interior and Congress beforehand, the April 20, 2010 oil spill from the Deepwater Horizon drilling rig primarily spurred the MMS reorganization. *See Reorganization of the Minerals Management Service in the Aftermath of the Deepwater Horizon Oil Spill*, Congressional Research Service (Nov. 10, 2010), at 1-3, *available at* https://fas.org/sgp/crs/misc/R41485.pdf.

and Budget, ONRR oversees revenue collection and disbursement from oil and gas production on the OCS.[1] Parties associated with OCS leases[2] are required to submit to ONRR monthly production and royalty reports,[3] monthly royalty payments due for that month's production,[4] and rental payments at a frequency specified by the terms of the OCS lease.[5] ONRR has broad auditing authority in order to ensure compliance with reporting and payment requirements under OCS leases, as well as other applicable regulations and orders.[6] Additionally, ONRR can effectuate debt collection by either referring debt to the U.S. Department of the Treasury or recommending revocation of a debtor's ability to engage in OCS leasing;[7] ONRR may even assess civil penalties for a failure to make royalty payments or for other violations.[8]

ONRR's disbursement of revenue to the states is guided by multiple revenue sharing programs under OCSLA. Coastal states receive 27% of revenues generated from OCS oil and gas leases that are located within the first three nautical miles of the OCS seaward of their territorial limits (colloquially referred to as the "8(g) zone").[9] Coastal states within 15 nautical miles of the center of an OCS renewable energy project, where the project is located at least partially in the state's "8(g) zone," share in a portion of 27% of generated revenues from that OCS lease.[10] Finally, the four "Gulf producing States"—Alabama, Louisiana, Mississippi, and Texas[11]—and their local governments are authorized to share 37.5% of qualified revenues from certain OCS leases in the Gulf of Mexico.[12]

## § 29:21 The Bureau of Safety and Environmental Enforcement

BSEE is authorized to regulate the exploration, development, and operations on the OCS,[1] ensuring that these practices are conducted in a manner that promotes human health, safety, and environmental protection.[2]

BSEE oversees the permitting program for OCS activities, which encompasses the drilling of wells;[3] permits for the installation, modification, or repair of platforms;[4]

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**[Section 29:20]**

[1] *Interior Establishes Office of Natural Resources Revenue*, U.S. DEPT. OF THE INTERIOR, https://www.doi.gov/pressreleases/news/pressreleases/Interior-Establishes-Office-of-Natural-Resources-Revenue (last visited June 16, 2021).

[2] ONRR's reporting and royalty payment requirements apply to all OCS lessees or anyone "who is assigned or assumes an obligation to report or make payment to ONRR." 30 C.F.R. § 1210.02 (2021); *see also* 30 C.F.R. § 1218.52 (2021) (outlining instructions for OCS lessee on how to designate person to make payments under OCS lease).

[3] 30 C.F.R. §§ 1210.101 to 1210.106 (2021); 30 C.F.R. §§ 1210.50 to 1210.61 (2021).

[4] 30 C.F.R. § 1218.150 (2021); 30 C.F.R. § 1218.50(a) (2021).

[5] 30 C.F.R. § 1218.150 (2021); 30 C.F.R. § 1218.50(a) (2021).

[6] 30 C.F.R. § 1217.50 (2021).

[7] 30 C.F.R. § 1218.702 (2021); 30 C.F.R. § 1218.705 (2021).

[8] 30 C.F.R. §§ 1241.1 to 1241.74 (2021).

[9] 43 U.S.C. § 1337(8)(g)(2).

[10] 43 U.S.C. § 1337(8)(p)(2)(B).

[11] *See* Gulf of Mexico Energy Security Act, Pub. L. No. 109-432, 120 Stat. 3001; 30 C.F.R. § 1219.411 (2021); 30 C.F.R. § 1219.511 (2021).

[12] 30 C.F.R. § 1219.412 (2021); 30 C.F.R. § 1219.512(a) (2021).

**[Section 29:21]**

[1] *See supra* note 58; 30 C.F.R. § 250.101 (2021).

[2] 30 C.F.R. § 250.107 (2021).

[3] 30 C.F.R. § 250.410 (2021).

and pipeline right-of-way grants.[5] BSEE also requires the creation and implementation of safety and environmental management system (SEMS) programs[6] and Oil Spill Response Plans (OSRPs).[7] SEMS programs are a compilation of policies and procedures that address the potential safety and environmental hazards that can arise from operations,[8] including a demonstration that the program meets industry standards adopted by the American Petroleum Institute.[9] An OSRP must demonstrate that OCS facility owners and/or operators have sufficient measures and resources in place to mitigate or prevent a release of oil from a facility.[10] These measures and resources include an emergency response action plan, equipment inventory, relevant contractual agreements, training and drills, a dispersant use plan and *in situ* burning plan, and a worst case discharge scenario.[11] Facility owners and/or operators must follow an OSRP in the event of an oil spill.[12]

BSEE's oversight of OCS operations extends throughout the life of the well at an OCS facility, including the decommissioning of inactive wells.[13] With this oversight comes necessary inspection and enforcement authority,[14] and BSEE even has the ability to declare an OCS facility's operation as "unacceptable," which could prompt BOEM to disapprove or revoke a party's designation as operator of an OCS facility.[15]

## § 29:22 The Bureau of Ocean Energy Management

BOEM oversees all leasing activities on the OCS and ensures compliance with OCS lease terms and conditions.[1] The leasing program established by OCSLA consists of four primary procedural stages:[2] (1) preparation and maintenance of a five-year program of proposed lease sales;[3] (2) issuance of leases in accordance with the five-year program;[4] (3) review of lessees' plans for geological and geophysical exploration of the OCS pursuant to an issued lease;[5] and (4) review of lessees' plans for the development and production of oil or gas from the lease area.[6]

## § 29:23 The Bureau of Ocean Energy Management—Five-Year Oil and Gas Leasing Program

OCSLA requires that the Secretary of the Interior prepare a five-year program.

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[4] 30 C.F.R. § 250.905 (2021).

[5] 30 C.F.R. § 250.1015 (2021).

[6] 30 C.F.R. § 250.1900 (2021).

[7] 30 C.F.R. § 254.2(a) (2021).

[8] 30 C.F.R. § 250.1901 (2021); *see* 30 C.F.R. § 250.1902 (2021) (outlining SEMS program minimum requirements).

[9] 30 C.F.R. § 250.1902(c) (2021); 30 C.F.R. § 250.198(h)(79) (2021).

[10] 30 C.F.R. § 254.5(a) (2021).

[11] 30 C.F.R. § 254.21(b) (2021).

[12] 30 C.F.R. § 254.5(a) (2021).

[13] 30 C.F.R. § 250.1703 (2021).

[14] 30 C.F.R. §§ 250.130, 250.1400 (2021).

[15] 30 C.F.R. § 250.135 (2021); *see* 30 C.F.R. § 250.136 (2021) (establishing criteria for "unacceptable" operating performance).

**[Section 29:22]**

[1] *See supra* note 58; 30 C.F.R. § 550.101 (2021).

[2] 43 U.S.C. § 1334(a).

[3] 43 U.S.C. § 1344(a).

[4] 43 U.S.C. § 1337(a).

[5] 43 U.S.C. § 1340.

[6] 43 U.S.C. § 1351.

The program must include a schedule of oil and gas lease sales and indicate the size, timing, and location of proposed leasing activity, as determined by the Secretary, to best meet national energy needs for the five-year period following its approval while also addressing a variety of economic, environmental, and social considerations.[1] BOEM is tasked with oversight of the five-year program.[2]

In developing the five-year program, BOEM must conduct a lengthy procedural process. BOEM first considers any nominations for areas to be included or excluded from OCS leasing—this includes consulting with the U.S. Department of Energy; requesting governors of affected states to identify laws, goals, and policies to be considered; and publishing a Request for Information (RFI) in the Federal Register.[3] The information collected during this process is used by BOEM to create a proposed five-year program that establishes a schedule it will use as a basis for considering where and when leasing might be appropriate over a five-year period.[4] BOEM then issues a Draft Proposed Program (DPP) to governors of affected states for review and comment 60 days before publishing the Proposed Program (PP).[5] The PP is then issued with a 90-day public commenting period.[6] A Proposed Final Program (PFP) is then published and transmitted to Congress and the President.[7] The PFP becomes the Final Program 60 days after it has been presented to Congress.[8]

The current Final Program for 2017-2022 scheduled 11 potential lease sales in two program areas: 10 sales in the combined Gulf of Mexico (GOM) Program Area, and one sale in the Cook Inlet Program Area in offshore Alaska.[9] Eight of the 11 potential lease sales have already occurred.[10] The ninth scheduled lease sale, Sale 258, was scheduled to take place in the Cook Inlet Planning Area in 2021.[11] On January 13, 2021, BOEM released an Area Identification Decision and draft Environmental Impact Statement (EIS) analyzing the potential environmental impacts of holding the proposed sale. A Notice of Availability of these documents was published in the Federal Register on January 15, 2021, with a public comment period set to run from January 16 to March 1, 2021.[12] But on February 4, 2021, BOEM canceled the public comment period and virtual public hearings after newly inaugurated President Joe Biden issued Executive Order 14008 directing the Secretary of the Interior to pause new oil and gas leases in offshore waters pending

**[Section 29:23]**

[1] 43 U.S.C. § 1344(a); 30 C.F.R. § 556.100 (2021).

[2] 30 C.F.R. § 556.200 (2021).

[3] 30 C.F.R. § 556.202 (2021).

[4] 30 C.F.R. § 556.203 (2021).

[5] 30 C.F.R. § 556.203(a) (2021).

[6] 30 C.F.R. § 556.204 (2021).

[7] 30 C.F.R. § 556.205 (2021).

[8] 30 C.F.R. § 556.205 (2021).

[9] BUREAU OF OCEAN ENERGY MANAGEMENT, "2017-2022 Outer Continental Shelf Oil and Gas Leasing Proposed Final Program" (November 2016), at S-4, *available at* https://www.boem.gov/sites/default/files/oil-and-gas-energy-program/Leasing/Five-Year-Program/2017-2022/2017-2022-OCS-Oil-and-Gas-Leasing-PFP.pdf (last visited June 16, 2021).

[10] BUREAU OF OCEAN ENERGY MANAGEMENT, "2017–2022 Lease Sale Schedule," *available at* https://www.boem.gov/2017-2022-lease-sale-schedule (last visited June 16, 2021). As described on the schedule, lease sale numbers 249-257 were in the Gulf of Mexico Region, lease sale number 258 was for the Cook Inlet region, and lease sales 259 and 261 are scheduled for the Gulf of Mexico Region.

[11] BUREAU OF OCEAN ENERGY MANAGEMENT, "Lease Sale 258," *available at* https://www.boem.gov/ak258 (last visited June 16, 2021).

[12] BUREAU OF OCEAN ENERGY MANAGEMENT, "Lease Sale 258," *available at* https://www.boem.gov/ak258 (last visited June 16, 2021).

review of federal oil and gas permitting and leasing policies.[13] The executive order requires the Secretary to reconsider these practices in light of its stewardship responsibilities, "including potential climate and other impacts associated with oil and gas activities."[14] The Secretary of the Interior is also required to consider whether to adjust royalties associated with OCS resources to account for corresponding climate costs.[15]

## § 29:24 The Bureau of Ocean Energy Management—Leasing

With a five-year program established, BOEM can begin OCS leasing. The lease sale process is initiated with a Call for Information and Nomination that is published in the Federal Register, which requests information on areas of interest, including potential multiple uses and other socioeconomic, biological, and environmental information.[1] Considering this input and other relevant information, BOEM develops a recommendation of areas proposed for leasing for the Secretary of the Interior.[2] Areas approved by the Secretary of the Interior are identified and announced in the Federal Register, and BOEM evaluates these areas for further consideration of potential human and environmental impacts, in some cases developing measures (including lease stipulations) to mitigate these impacts.[3]

BOEM then develops a proposed notice of sale that, once approved by the Secretary of the Interior, is sent to the governor of any affected state for comments and published in the Federal Register.[4] After consideration of any comments received in response to the proposed notice of sale,[5] BOEM will publish final notice of a lease sale in the Federal Register at least 30 days before the date of the sale.[6]

Lease sales are conducted by competitive sealed bidding.[7] BOEM requires formal qualification in order to bid on or to be approved as an assignee of an OCS lease;[8] even if an entity meets qualification requirements, BOEM has the discretion to disqualify that entity if they fail to meet due diligence requirements or have an unacceptable operating performance.[9] Further, BOEM retains the discretion to reject any bid.[10] Once BOEM accepts a bid, the winning bidder is required to execute the lease documents and make all remaining payments (including the first year's rent) within 11 days of acceptance.[11] The lease is effective beginning the month following

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[13] Bureau of Ocean Energy Management, "BOEM Cancels Comment Period, Virtual Meetings for Proposed Lease Sale Offshore Alaska" (February 04, 2021), *available at* https://www.boem.gov/boem-cancels-comment-period-virtual-meetings-proposed-lease-sale-offshore (last visited June 16, 2021).

[14] Exec. Order No. 14008, "Tackling the Climate Crisis at Home and Abroad," 86 Fed. Reg. 7619 (Feb. 1, 2021) at § 208.

[15] Exec. Order No. 14008, "Tackling the Climate Crisis at Home and Abroad," 86 Fed. Reg. 7619 (Feb. 1, 2021) at § 208.

**[Section 29:24]**

[1] 30 C.F.R. § 556.301 (2021).

[2] 30 C.F.R. § 556.302(a) (2021).

[3] 30 C.F.R. § 556.302(b) (2021).

[4] 30 C.F.R. § 556.304 (2021); 30 C.F.R. § 556.305(a) (2021).

[5] 30 C.F.R. § 556.307 (2021).

[6] 30 C.F.R. § 556.308(a) (2021).

[7] 30 C.F.R. § 556.308(b) (2021).

[8] 30 C.F.R. § 556.400 (2021); *see* 30 C.F.R. § 556.401 (2021) (describing qualification requirements).

[9] 30 C.F.R. § 556.403(b), (c) (2021).

[10] 30 C.F.R. § 556.516(b) (2021).

[11] 30 C.F.R. § 556.520 (2021).

the date that BOEM executes the lease.[12]

## § 29:25 The Bureau of Ocean Energy Management—Plans Required for Exploration, Production, and Development

Once an OCS lease is issued, the operator may not begin exploration, development, or production until submission and approval of an Exploration Plan (EP) and a Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD).[1] Generally, all of these plans must demonstrate that the proposed activities conform with OCSLA, are safe, do not reasonably interfere with other OCS uses, and adequately protect human health and the environment.[2]

An EP must include a description and schedule of the proposed exploration activity from start to completion that includes the locations of proposed wells as well as descriptions of drilling units and any other equipment to be used.[3] Further, BOEM regulations require a significant amount of information to accompany any submitted EP.[4] General information that needs to accompany the EP includes a listing of approvals and permits that must be obtained for exploration activities; information on drilling fluids, chemical products, and "new and unusual technology"[5] that will be used during exploration activities; bonds, oil spill financial responsibility, and well control statements; a discussion on suspension of operations; a blowout scenario; and relevant contact information.[6] While the general information alone seems comprehensive, this category pales in comparison to the more specific required information related to environmental protection, human health and safety, resources, and planning listed at length in BOEM regulations.[7] Once an EP is properly submitted, BOEM, while coordinating with affected states, will review the EP to determine compliance with OCSLA, BOEM regulations, and other applicable law.[8] BOEM has 30 days to approve, disapprove, or require modification of the EP.[9]

The requirements for what must be included in a DPP or DOCD,[10] as well the information to accompany either plan,[11] are substantially similar to EP requirements. Once a DPP or DOCD has been properly submitted, however, BOEM consults with affected states and local governments, and issues a copy for public review and comment when determining whether the plans comply with all applicable requirements.[12] As with an EP, BOEM has 30 days to approve, disapprove, or require modification

[12] 30 C.F.R. § 556.521 (2021).

**[Section 29:25]**

[1] 30 C.F.R. § 550.201(a) (2021). A DPP is required to conduct any development and production activities in OCS areas other than the Western Gulf of Mexico; for those areas, a DOCD is required. 30 C.F.R. § 550.201(a) (2021).

[2] 30 C.F.R. § 550.202 (2021).

[3] 30 C.F.R. § 550.211 (2021).

[4] 30 C.F.R. § 550.212 (2021).

[5] "New or unusual technology" means technology that has not been previously or extensively used by BOEM, has not been previously used under the anticipated operating conditions, or has operating characteristics outside of established performance parameters. 30 C.F.R. § 550.200 (2021).

[6] 30 C.F.R. § 550.212(a) (2021); 30 C.F.R. § 550.213 (2021).

[7] 30 C.F.R. § 550.212(b) to (p) (2021).

[8] 30 C.F.R. § 550.232 (2021).

[9] 30 C.F.R. § 550.233 (2021).

[10] 30 C.F.R. § 550.241 (2021).

[11] 30 C.F.R. § 550.242 (2021).

[12] 30 C.F.R. § 550.267 (2021).

of a DPP or DOCD.[13]

Failure to conduct OCS lease activities according to an approved EP, DPP, or DOCD can result in a BOEM enforcement action, which may include civil penalties.[14] BOEM also has the authority to forfeit or cancel an OCS lease for failure to follow an approved plan.[15]

## IV. PRESIDENTIAL WITHDRAWAL AUTHORITY UNDER OCSLA AND *LEAGUE OF CONSERVATION VOTERS*

### § 29:26 Generally

OCSLA provides that the President "may, from time to time, withdraw from disposition any of the unleased lands of the outer Continental Shelf."[1] This broad authority allows the President to withdraw any area of the OCS, either temporarily or permanently, for any public purpose. Since passage of OCSLA in 1953, six presidents have used this executive authority.[2] In 2015, President Barack Obama withdrew coastal areas in the Arctic's Beaufort and Chukchi Seas, citing the importance of these areas to Alaska Natives' subsistence as well as wildlife protection.[3] In 2016, President Obama withdrew more areas from the U.S. Arctic Ocean and areas of the Atlantic Ocean, citing similar reasons concerning conservation and environmental protection.[4] The combined withdrawals from 2015 and 2016 totaled 128 million acres.[5]

In 2017, in an unprecedented move, President Donald Trump purported to revoke these withdrawals with the issuance of Executive Order 13795,[6] which prompted a lawsuit in the United States District Court for the District of Alaska.[7] In *League of Conservations Voters v. Trump*, the plaintiffs, various environmental groups, alleged that the President's revocation violated the Property Clause of the U.S. Constitution[8] and the withdrawal authority under OCSLA.[9]

The U.S. District Court for the District of Alaska resolved the issue by means of statutory interpretation.[10] First, the court found that OCSLA's text was ambiguous

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[13] 30 C.F.R. § 550.270 (2021).

[14] 30 C.F.R. § 550.280(a)(1) (2021).

[15] 30 C.F.R. § 550.280(a)(2) (2021).

**[Section 29:26]**

[1] 43 U.S.C. § 1341(a).

[2] *Briefer on Presidential Withdrawal Under OCSLA Sec. 12(a)*, NAT. RES. DEF. COUNCIL (2016), *available at* https://www.nrdc.org/sites/default/files/briefer-on-ocsla-withdrawal-authority_20161121_0.pdf (last visited June 16, 2021).

[3] Memorandum on Withdrawal of Certain Areas of the United States Outer Continental Shelf Offshore Alaska From Leasing Disposition, (Jan. 27, 2015) *available at*: https://obamawhitehouse.archives.gov/the-press-office/2015/01/27/presidential-memorandum-withdrawal-certain-areas-united-states-outer-con (last visited June 16, 2021).

[4] Memorandum on Withdrawal of Certain Portions of the United States Arctic Outer Continental Shelf From Mineral Leasing, DCPD201600860 (Dec. 20, 2016); Memorandum on Withdrawal of Certain Areas off the Atlantic Coast on the Outer Continental Shelf From Mineral Leasing, DCPD201600861 (Dec. 20, 2016)).

[5] League of Conservation Voters v. Trump, 303 F. Supp. 3d 985, 990 (D. Alaska 2018).

[6] Exec. Order No. 13795, 82 Fed. Reg. 20815, §§ 4(c), 5 (Apr. 28, 2017).

[7] League of Conservation Voters v. Trump, 363 F. Supp. 3d 1013 (D. Alaska 2019), vacated and remanded, 843 Fed. Appx. 937 (9th Cir. 2021).

[8] U.S. Const. art. IV, § 3, cl. 2.

[9] *League of Conservation Voters*, 363 F.Supp.3d at 1017.

[10] *League of Conservation Voters*, 363 F.Supp.3d at 1017.

and could be interpreted to permit the President to revoke prior withdrawals.[11] However, considering the context of OCSLA, the court found that interpreting the language concerning withdrawal authority as "entirely protective" gives best effect to all of the statute's provisions.[12] The court also acknowledged the general principle that, "had Congress intended to grant the President revocation authority, it could have done so explicitly."[13] For these and other reasons, the court held that OCSLA did not grant a president the authority to revoke prior withdrawals of unleased land and that President Trump's executive order was unlawful because it exceeded the executive authority under the statute.[14]

The court's decision has since been appealed to the Ninth Circuit.[15] However, on January 20, 2021, President Biden issued Executive Order 13990, which, among other executive actions, reinstated President Obama's withdrawals and revoked President's Trump's Executive Order 13795.[16] Thus it is unclear whether the Ninth Circuit will fully address the limits of the President's withdrawal authority under OCSLA, as it appears for the time being that the current administration has returned to the traditional exercise of executive power under the statute.

## V. DEVELOPMENT ON TRIBAL LANDS

### § 29:27 Introduction

Indian lands in the United States are commonly comprised of a combination of fee,[1] tribal,[2] and allotted lands.[3] This fragmented ownership creates unique issues not normally encountered outside of an Indian reservation.[4] This situation is particularly relevant for oil and gas development because Indian lands are estimated to contain 3-4% of the known oil and gas reserves in the United States.[5]

Any oil and gas company contemplating development on Indian lands must be aware of a few basic principles of Indian law: (1) the federal government has jurisdiction over Indian trust lands;[6] (2) Congress has plenary power over Indian affairs and lands, subject only to constitutional limitations;[7] and (3) no interest in trust lands, whether beneficially owned by a tribe or by an individual allottee, may be

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[11]*League of Conservation Voters*, 363 F.Supp.3d at 1024.

[12]*League of Conservation Voters*, 363 F.Supp.3d at 1024–25.

[13]*League of Conservation Voters*, 363 F.Supp.3d at 1027; *League of Conservation Voters*, 363 F.Supp.3d at 1025–28.

[14]*League of Conservation Voters*, 363 F.Supp.3d at 1027.

[15]League of Conservation Voters v. Biden, 2021 WL 279079 (9th Cir. 2021).

[16]Exec. Order 13990, 86 Fed. Reg. 7037, §§ 4(b), 7 (Jan. 20, 2021).

**[Section 29:27]**

[1]"Fee lands," as used in this paper, mean privately-owned lands.

[2]"Tribal lands," as used in this paper, mean lands owned by the United States in trust for an Indian tribe, or owned by the tribe itself, subject to Federal restrictions on alienation or encumbrance.

[3]"Allotted lands" as used in this paper, mean lands owned by the United States in trust for individual Indian owners, or owned by individual Indian owners themselves, subject to Federal restraints on alienation or encumbrance.

[4]*See* COLBY L. BRANCH AND ALAN C. BRYAN, *Indian Lands Right-of-Way*, Energy and Mineral Development in Indian County (Rocky Mt. Min. L. Fdn. 2014) (Hereinafter "Branch").

[5]*See* Felix S. Cohen's Handbook of Federal Indian Law, § 7.03[1] (Nell Jessup Newton ed., 2017) (Hereinafter "COHEN").

[6]The term "trust lands" is used in this paper to collectively refer to tribal and allotted lands.

[7]Delaware Tribal Business Committee v. Weeks, 430 U.S. 73, 84, 97 S. Ct. 911, 51 L. Ed. 2d 173 (1977).

transferred or conveyed absent congressional approval.[8]

This discussion is intended to provide useful background information for anyone interested in oil and gas development on Indian lands. An exhaustive review of statutory or regulatory procedure is not attempted. Issues specific to particular reservations or to particular applications are not discussed.

## A. APPLICABLE LAW

### 1. Federal Jurisdiction

### § 29:28 Background on Federal Indian Policy

During the early 19th century, the rapid growth of the United States created a demand for territorial expansion into the American West. Through conquest, treaties, and purchases, the United States acquired numerous Indian homelands. As settlement encroached on Indian lands, the Federal Government entered into treaties with Indian tribes which recognized the tribes' aboriginal right to occupy certain lands in exchange for cession of other lands.[1] National policy then shifted from removal of Indians to concentration on fixed reservations.[2] Therefore, certain lands were "reserved" from the public domain for the sole use and benefit of individual tribes.[3] Legal title to the reserved tribal lands remained in the United States, but beneficial title vested with the tribe, to be held in common for the benefit of all living members of the tribe.[4] This arrangement laid the foundation for the Federal Trust Doctrine.

### § 29:29 Federal Trust Obligation

As a general matter, the federal government has plenary power over Indian trust lands. The most basic cornerstone of Indian law is the federal government's long-established trust responsibility over Indian lands. The United States Supreme Court has long recognized "the distinctive obligation of trust incumbent upon the United States Government" with regards to matters affecting Indian tribes.[1] As the trustee of federal Indian lands, the government is held to the "most exacting fiduciary standards" in protecting the interests of Indian beneficial owners.[2] This trust obligation extends to all government officials, whether they are merely local federal employees or national decision-makers directing federal policy.[3]

As the legal title holder to tribal and individually allotted trust lands, the federal

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[8] *See* Oneida Indian Nation of N. Y. State v. Oneida County, New York, 414 U.S. 661, 678, 94 S. Ct. 772, 39 L. Ed. 2d 73 (1974) (asserting that "the Nonintercourse Acts . . .put in statutory form what was or came to be the accepted rule—that the extinguishment of Indian title required the consent of the United States").

**[Section 29:28]**

[1] Cohen, § 1.03[1].

[2] Cohen, § 1.03[6][a].

[3] Cohen, § 1.03[6][a]

[4] *See* Johnson v. M'Intosh, 21 U.S. 543, 588, 5 L. Ed. 681, 1823 WL 2465 (1823).

**[Section 29:29]**

[1] Seminole Nation v. U.S., 316 U.S. 286, 296, 62 S. Ct. 1049, 86 L. Ed. 1480, 86 L. Ed. 1777 (1942); *see also* Cherokee Nation v. State of Ga., 30 U.S. 1, 8 L. Ed. 25, 1831 WL 3974 (1831); U.S. v. Kagama, 118 U.S. 375, 6 S. Ct. 1109, 30 L. Ed. 228 (1886); Choctaw Nation v. U.S., 22 Ct. Cl. 476, 119 U.S. 1, 7 S. Ct. 75, 30 L. Ed. 306 (1886).

[2] Coast Indian Community v. U. S., 213 Ct. Cl. 129, 550 F.2d 639, 652 (1977); U.S. v. Mason, 412 U.S. 391, 398, 93 S. Ct. 2202, 37 L. Ed. 2d 22, 73-2 U.S. Tax Cas. (CCH) P 12935, 32 A.F.T.R.2d 73-6217 (1973).

[3] Seminole Nation, 316 U.S. at 297; Coast Indian Cmty., 550 F.2d at 653.

government's trust obligations are vast.[4] Federal statutes and regulations give the government full responsibility to manage trust resources and land for the benefit of Indian owners.[5] This responsibility includes the management of mineral resources. In fact, based on its statutory delegations, the federal government has developed a regulatory scheme that addresses all aspects of oil and gas development on trust lands.[6] The Secretary of the Interior (Secretary), through the Bureau of Indian Affairs (BIA), is obligated to maximize consideration and protect Indian payments under such leases.[7] In accordance with this regulatory scheme, there exist areas of exclusive federal jurisdiction where the Secretary or its federal agencies hold sole authority to address certain issues.[8] Whether the federal government holds exclusive authority or shares concurrent authority with state or tribal governments will depend on the nature of the dispute and the potential occupation of the issue by the federal agency. To the extent a company commences any development involving tribal or individually allotted trust lands, the federal government, mainly through the BIA, will have a significant role in reviewing and approving these transactions.

a. Trust Lands and Allotments

## § 29:30 General Allotment Act

Throughout the nineteenth century, Congress entered into various treaties and agreements, whereby tribal land was allotted to individual Indians in fee, subject to restrictions on alienation.[1] In 1887, Congress passed the General Allotment Act, also known as the "Dawes Act," to break apart tribal lands into separate tracts, which would then be allotted to individual tribal members or allottees.[2] Any lands remaining after each eligible tribal member received his or her allotment were considered "surplus lands," which were then "disposed of" to the public at large under the existing homestead laws.[3] As originally contemplated under the General Allotment Act, title to each allotment was to be held in trust by the United States for the individual Indian owner for a period of 25 years.[4] The purpose of this provision was to allow the Indian owner time to become "competent" to manage his or her affairs.[5] After such time, a patent was to issue to the Indian owner in fee simple, thereby terminating the United States' ownership and control over the land.

## § 29:31 Burke Act

In 1906, Congress enacted the Burke Act, which amended the General Allotment Act to eliminate all trust restrictions on allotments and authorized the Secretary to issue a fee patent to an allottee before expiration of the 25-year trust period established by the General Allotment Act, upon a conclusion that the allottee was

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[4] *See* Pawnee v. U.S., 830 F.2d 187, 190-91 (Fed. Cir. 1987).

[5] *See* U.S. v. Mitchell, 463 U.S. 206, 224, 103 S. Ct. 2961, 77 L. Ed. 2d 580 (1983).

[6] *See* 25 C.F.R. §§ 162.501 et seq (2021).

[7] *Pawnee*, 830 F.2d at 190–91.

[8] *See, e.g.*, Rainbow Resources, Inc. v. Calf Looking, 521 F. Supp. 682, 684 (D. Mont. 1981).

**[Section 29:30]**

[1] *See* COHEN, § 16.03[2][a].

[2] General Allotment Act, 24 Stat. 388 (1887).

[3] COHEN, § 1.04.

[4] General Allotment Act, ch. 119, § 5, 24 Stat. 388.

[5] General Allotment Act, ch. 119, § 5, 24 Stat. 388.

"competent and capable of managing his or her affairs."[1] The Burke Act led to the increased alienation of Indian lands.[2] Notably, the Act did not require an allottee's approval prior to the issuance of a fee patent and the Secretary of the Interior granted fee patents both to willing allottees and to a large numbers of Indians that did not seek fee title to the land.[3]

## § 29:32 Indian Reorganization Act

As a result of the United States' allotment policy, many Indians received a fee patent, and some sold their land to non-Indians. Significant "surplus lands" within the Reservation were also sold to non-Indians.[1] The policy of allotment effectively transformed large portions of tribal lands into a checkerboard of allotted and fee lands. By 1934, nearly 27 million acres of the land allotted to tribal members had transferred from Indian ownership into non-Indian fee ownership.[2] In response to this and other matters, Congress passed the Indian Reorganization Act of 1934.[3] This Act halted the practice of allotment, restored undisposed-of "surplus lands" to tribal trust ownership, and indefinitely extended the trust period over allotted lands.[4] Consequently, most allotments that had not been transferred to fee ownership by 1934 remain held by the United States in trust today, with the beneficial ownership held by the heirs and successors of the original allottees.[5]

## § 29:33 Statutory Authority

The Constitution vests in Congress broad authority to regulate commerce with the Indian tribes.[1] Pursuant to this authority, Congress may authorize the non-Indian leasing of trust lands for oil and gas development. In 1891, Congress passed the first general leasing act which authorized the leasing of Indian lands for grazing and mining purposes.[2] The Act of 1891 was amended several times. Unfortunately, each amendment added another layer of confusion to the existing leasing process.[3]

## § 29:34 Indian Mineral Leasing Act

In 1938, Congress enacted the Indian Mineral Leasing Act (IMLA) in order to cre-

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**[Section 29:31]**

[1]Pub. L. No. 59-149, 34 Stat. 182 (1906) (amending 25 U.S.C. § 349).

[2]9-67 Powell on Real Property § 67.07.

[3]COHEN, § 16.03[4][b][iii].

**[Section 29:32]**

[1]COHEN, § 1.04.

[2]COHEN, § 16.03[2][b] at 1073.

[3]Wheeler-Howard Act (Indian Reorganization Act), 48 Stat. 984–988 (1934) (codified as amended at 25 U.S.C. §§ 5101 et seq.).

[4]Wheeler-Howard Act (Indian Reorganization Act), 48 Stat. 984–988 (1934) (codified as amended at 25 U.S.C. §§ 5101 et seq.).

[5]*See* COHEN, § 16.03[2][b].

**[Section 29:33]**

[1]U.S. CONST., art. I, § 2, cl. 3.

[2]*See* 25 U.S.C. § 397.

[3]COHEN, § 17.03[2][a]. The existing leasing structure had no uniformity concerning tribal consent, state taxation, or lease duration. 25 U.S.C. § 397.

ate a uniform process for leasing tribal minerals.[1] The stated purposes of the IMLA included: (1) to achieve uniformity in mineral leasing laws governing Indian lands; (2) to help achieve the goal of the Indian Reorganization Act to revitalize Indian tribal governments; and (3) to promote tribal economic development by ensuring the greatest return on tribal minerals.[2] Tribal leases could only be granted upon the consent of the Tribe and the approval of the Secretary.[3] The duration of IMLA leases were "not to exceed 10 years and so long thereafter as minerals are produced in paying quantities."[4] The IMLA also included a public notice and competitive bidding process for leases, but the Secretary retained the authority to reject bids and re-advertise the lease when a bid was not in the best interest of the Tribe.[5] The standard for "best interest" of a tribe is found in BIA's regulations implementing the IMLA:

> In considering whether it is "in the best interest of the Indian mineral owner" to take a certain action (such as approval of a lease, permit, unitization or communitization agreement), the Secretary shall consider any relevant factor, including, but not limited to: economic considerations, such as date of lease expiration; probable financial effect on the Indian mineral owner; leasability of land concerned; need for change in the terms of the existing lease; marketability; and potential environmental, social, and cultural effects.[6]

While the IMLA clarified the oil and gas leasing process, it was not ideal for all situations. Namely, the IMLA did not apply to leases of allotted lands.[7] Also, from the Indian mineral owners' perspective, leases provided no mechanism that would enable tribes to share in the profits generated from the minerals.[8] For example, bonuses, rents, and royalties were claimed to be lower than warranted by market conditions.[9] In addition, Indian tribes had limited authority to participate in development and management decisions, to bargain for lease terms,[10] or to provide environmental and cultural protections.[11] As a result of these issues, several tribes began to negotiate oil and gas leases on their own outside the scope of IMLA. Although the Secretary approved several of these non-IMLA leases, in 1980 it determined that it had no such authority, raising doubts on the legality of the existing negotiated leases.[12]

## § 29:35 Allotted Lands Leasing Act

In 1909, Congress enacted the Allotted Lands Leasing Act (Act of 1909) in order

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**[Section 29:34]**

[1] Act of May 11, 1938, 52. Stat. 347 (codified at 25 U.S.C. §§ 396a to 396g).

[2] *See* COHEN at § 17.03[2][a].

[3] 25 U.S.C. § 396a.

[4] 25 U.S.C. § 396a.

[5] 25 U.S.C. § 396b.

[6] 25 C.F.R. § 211.3 (2021).

[7] 25 U.S.C. § 396a.

[8] COHEN, § 17.03[2][a].

[9] COHEN, § 17.03[2][a].

[10] If the bid received in the public notice and competitive bidding process was not in the best interest of the tribe, the Secretary could enter into negotiations on behalf of the tribe. 25 U.S.C. § 396b.

[11] COHEN, § 17.03[2][a].

[12] COHEN, § 17.03[2][a].

to authorize the general leasing of allotted lands for mining purposes.[1] The Act specifically authorized the Secretary to make all such rules and regulations as may be necessary to carry out the purposes of the Act.[2] BIA Regulations implementing the Allotted Lands Leasing Act in 25 C.F.R. part 212 generally incorporate by reference the corresponding IMLA tribal lands regulations in 25 C.F.R. part 211. Pursuant to the Act of 1909, the Secretary may issue a lease, based on the best interest of the allottees, upon the consent of a majority of the allottees owning an interest in the tract.[3]

## § 29:36 Indian Mineral Development Act

In 1982, Congress passed the Indian Mineral Development Act (IMDA) in an effort to further the United States' new policy of Indian self-determination.[1] The IMDA authorized Indian mineral owners to negotiate and enter into mineral development agreements. The term "Minerals Agreement" is flexible and includes:

> Any joint venture, operating, production sharing, service, managerial, lease . . . contract, or other minerals agreement; or any amendment, supplement or other modification of such minerals agreement, providing for the exploration for, or extraction, processing, or other development of minerals in which an Indian mineral owner owns a beneficial or restricted interest, or providing for the sale or other disposition of the production or products of such minerals.[2]

A Minerals Agreement is still subject to approval by the Secretary.[3] Therefore, while the IMDA does not require any particular form of Minerals Agreement, the Secretary's approval of a Minerals Agreement will be affected by the agreement's terms and whether the agreement is "in the best interest of the Indian tribe."[4] In approving or disproving a Mineral Agreement, the Secretary must consider "the potential economic return to the tribe; the potential environmental, social, and cultural effects on the tribe; and provisions for resolving disputes that may arise between the parties to the agreement."[5] After the Secretary approves a Minerals Agreement under the provisions of the IMDA, the United States is shielded from liability for losses sustained by a tribe under a Minerals Agreement, but will still protect the tribe or individual Indian against a violation by the mineral development company.[6]

## § 29:37 Indian Tribal Energy Development and Self-Determination Act

Consistent with the policy of tribal self-determination, Congress enacted the Indian Tribal Energy Development and Self-Determination Act of 2005 (Act of 2005) which authorized tribes to develop their own economic and environmental review

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**[Section 29:35]**

[1] Act of March 3, 1909, 35 Stat. 783 (codified at 25 U.S.C. § 396).

[2] Act of March 3, 1909, 35 Stat. 783 (codified at 25 U.S.C. § 396).

[3] 25 C.F.R. § 212.20 (2021); 25 U.S.C. § 2218(b).

**[Section 29:36]**

[1] Act of December 22, 1982, Pub. L. No. 97-382, 96 Stat. 1938 (codified at 25 U.S.C. §§ 2101 to 2108). The IMDA was intended "first, to further the policy of self-determination and second, to maximize the financial return tribes can expect for their valuable mineral resources." Quantum Exploration, Inc. v. Clark, 780 F.2d 1457, 1458 (9th Cir. 1986).

[2] 25 C.F.R. § 225.3 (2021).

[3] 25 U.S.C. § 2102(a).

[4] 25 U.S.C. § 2103(b).

[5] 25 U.S.C. § 2103(b).

[6] 25 U.S.C. § 2103(e).

capabilities and secure secretarial approval to review and approve certain agreements, eliminating the need for BIA approval.[1] Specifically, the Act of 2005 authorizes tribes and the Secretary to enter into Tribal Energy Resource Agreements (TERAs) pursuant to which a tribal agency may alone review, approve, and regulate energy resource development.[2] The TERA process allows the Secretary to pre-approve certain mineral development agreements. Under Section 3504, an approved TERA may allow the tribe to enter into a lease or business agreement for the "exploration for, extraction of, processing of, or other development of energy mineral resources of the Indian tribe located on tribal land."[3] The Act of 2005 also authorizes the pooling, unitization, or communitization of tribal minerals located on trust land.[4]

A TERA may also authorize a tribe to grant rights-of-way over trust land if the right-of-way serves any of the following:

(A) an electric production, generation, transmission, or distribution facility (including a facility that produces electricity from renewable energy resources) located on tribal land;

(B) a facility located on tribal land that extracts, produces, processes, or refines energy resources; or

(C) the purposes, or facilitates in carrying out the purposes, of any lease or agreement entered into for energy resource development on tribal land.[5]

The regulations implementing the Act of 2005 contain a detailed process for approving a TERA.[6] The Act of 2005 appears to be underutilized. Although several tribes initiated the TERA process, no tribe has yet entered into a TERA.[7] This may be due to the complexity of the Act of 2005 regulations, as well as the anticipated cost and time involved in creating and administering such an agreement.

### b. Agency roles in Oil and Gas Development on Indian Lands

## § 29:38 Bureau of Indian Affairs

Congress delegated substantial authority to the Secretary for the implementation of the laws which apply to the development of oil and gas on trust lands.[1] The Sec-

**[Section 29:37]**

[1] 42 U.S.C. §§ 7144e & 16001 (Title V of the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594).

[2] 25 U.S.C. § 3504.

[3] 25 U.S.C. § 3504(a)(1)(A).

[4] 25 U.S.C. § 3504(a)(1)(C).

[5] 25 U.S.C. § 3504(b)(1). The Act of 2005 originally did not authorize rights-of-way for roads or other non-pipeline, non-transmission access or other facilities often required for energy development. The Act of 2005 was amended by Act of Dec. 18, 2018, P.L. 115-325, Title I, §§ 103(a), 105(d), 132 Stat. 4447, 4456 to include subsection C. Subsection C is on its face broad enough to include rights-of-way for roads or other facilities.

[6] *See* 25 C.F.R. pt. 224 (2021).

[7] TANA FITZPATRICK, *Tribal Energy Resource Agreements (TERAs): Approval Process and Selected Issues for Congress*, Congressional Research Service (July 9, 2020).

**[Section 29:38]**

[1] In 25 U.S.C. § 2, Congress specifically provided that "[t]he Commissioner of Indian Affairs shall, under the direction of the Secretary of the Interior, and agreeably with such regulations as the President may prescribe, have the management of all Indian Affairs and all matters arising out of Indian relations." *See also* 25 U.S.C. § 13 ("[T]he Bureau of Indian Affairs, under the supervision of the Secretary of the Interior, shall direct, supervise, and expend such moneys as Congress may from time to time appropriate, for the benefit, care, and assistance of the Indians throughout the United States.").

retary of the Interior has further delegated this authority to the BIA.[2] Consequently, the BIA has the authority to promulgate regulations necessary to implement its statutory obligations and duties related to the management of Indian trust lands.[3] Most relevant for oil and gas operations, BIA's responsibilities include the negotiation, approval, and cancellation of oil and gas leases;[4] the management of leasing of oil and gas resources;[5] the environmental review of proposed operations;[6] and the acquisition of land in trust status for the benefit of individual Indians and Indian tribes.[7]

### § 29:39 Bureau of Land Management

The Bureau of Land Management (BLM)'s regulations govern oil and gas operations on "restricted Indian land leases," as well as leases under the jurisdiction of the Secretary.[1] BLM's responsibilities on Indian lands include "resource evaluation, approval of drilling permits, mining and reclamation, production plans, mineral appraisals, inspection and enforcement, and production verification."[2] BLM's oil and gas regulations apply to leases that are approved under the IMLA and the IMDA, as well as leases of allotted lands.[3] BLM has general authority over Applications for Permits to Drill (APDs) for wells drilled on Indian Lands, but will consult with BIA as part of the APD process.[4] BLM also has responsibility of split estate lands when federal minerals are beneath tribal surface.[5]

### § 29:40 Office of Natural Resources Revenue

In 1982, Congress enacted the Federal Oil and Gas Royalty Management Act (FOGRMA) to improve royalty collection, management, and enforcement.[1] The Office of Natural Resources Revenue (ONRR) is the federal agency responsible for the collection and disbursement of royalties paid on production from leases on Indian lands.[2] ONRR's responsibilities include the collection of certain rents, royalties, and other payments; the receipt of sales and production reports; determining royalty liability; maintaining accounting records; auditing royalty payments and obligations; and for any and all other functions relating to royalty management on Indian oil

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[2] Cohen, § 5.03 [1].

[3] Cohen, § 5.03 [1].

[4] 25 C.F.R. pt. 162 (2021).

[5] 25 C.F.R. §§ 200, 211, 212, 225 (2021).

[6] 40 C.F.R. § 1500.6 (2021); 25 C.F.R. § 211.7 (2021).

[7] 25 C.F.R. pt. 151 (2021).

**[Section 29:39]**

[1] 43 C.F.R. § 3160.0-1 (2021).

[2] 25 C.F.R. § 211.4 (2021).

[3] 25 C.F.R. § 211.4 (2021); 25 C.F.R. § 212.4 (2021); 25 C.F.R. § 225.4 (2021); 43 C.F.R. § 3161.1 (2021).

[4] 43 C.F.R. § 3162.3-1 (2021); *see also* Federal Onshore Oil and Gas Order No. 1, 72 Fed. Reg. 10308 (Mar. 7, 2007).

[5] 43 C.F.R. § 3162.3-1 (2021); *see also* Federal Onshore Oil and Gas Order No. 1, 72 Fed. Reg. 10308 (Mar. 7, 2007).

**[Section 29:40]**

[1] Federal Oil and Gas Royalty Management Act, 96 Stat. 2448, codified at 30 U.S.C. §§ 1701 et seq.

[2] 25 C.F.R. § 211.6 (2021).

and gas leases.[3]

2. Other Federal Delegations

## § 29:41 Environmental Compliance

Most major federal environmental laws are relevant to oil and gas operations in Indian country.[1] For example, oil and gas development on Indian lands will generally be subject to the National Environmental Policy Act's (NEPA)[2] requirement that an environmental impact statement be prepared for all "major Federal actions significantly affecting the quality of the human environment."[3] Secretarial approval of tribal and allotted leases constitutes a major federal action; therefore, the Secretary must comply with NEPA in the approval process.[4] The Secretary must also determine whether an IMDA agreement does not have an adverse environmental impact before granting approval.[5] In addition, the Surface Mining Control and Reclamation Act of 1977 (SMCRA) governs the environmental aspects of surface exploration, drilling, and reclamation on Indian lands.[6]

Federal environmental laws operate under the principle of cooperative federalism, whereby the federal government establishes minimum standards and encourages state or local governments to implement and administer these federal minimums.[7] As a general rule, the United States Environmental Protection Agency (EPA) has primary environmental regulatory authority over operations within Indian reservations.[8] For purposes of enforcing applicable federal environmental laws, Indian reservations are considered "single administrative units."[9] State governments generally do not have environmental regulatory authority on Indian reservations absent a specific delegation from the EPA. With regard to Indian reservation lands (including non-Indian fee lands), a local tribe may receive delegations of environmental regulatory authority from the EPA, similar to those received by state governments outside the reservation, but only if that tribe meets certain conditions.[10] Specifically, the tribe must apply for Treatment as a State (TAS) status and be approved by the EPA in order to administer federal environmental standards.[11] Once a tribe has obtained TAS status for one environmental statute, it is much easier for the tribe to apply and have the status granted for another statute.

Even when a tribe has not obtained TAS status, the EPA and other federal agencies are required to consult with the tribes with respect to historic preservation

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[3] 30 C.F.R. § 1201.100 (2021).

**[Section 29:41]**

[1] COHEN, § 17.03[3].

[2] 42 U.S.C. §§ 4321 et seq.

[3] 42 U.S.C. § 4332(2)(C).

[4] *See* 25 C.F.R. § 211.7(a) (2021); 25 C.F.R. § 225.24(a) (2021).

[5] 25 C.F.R. § 225.22(c)(2) (2021).

[6] 30 U.S.C. §§ 1201 to 1328; the regulations provide that the act applies to both IMLA leases, 25 C.F.R. § 211.5 (2021), and IMDA minerals agreements, 25 C.F.R. § 225.5 (2021).

[7] *See, e.g.*, Bell v. Cheswick Generating Station, 734 F.3d 188, 190, 77 Env't. Rep. Cas. (BNA) 1395 (3d Cir. 2013).

[8] *See* EPA Policy for the Administration of Environmental Programs on Indian Reservations (1984).

[9] *See* EPA Policy for the Administration of Environmental Programs on Indian Reservations (1984).

[10] *See, e.g.,* 33 U.S.C. § 1377(e) (Clean Water Act); 42 U.S.C. § 7601 (Clean Air Act); 42 U.S.C. § 300j-11(a) (Safe Drinking Water Act).

[11] *See, e.g.,* 33 U.S.C. § 1377(e) (Clean Water Act); 42 U.S.C. § 7601 (Clean Air Act); 42 U.S.C. § 300j-11(a) (Safe Drinking Water Act).

prior to the issuance of any oil and gas lease as discussed below.[12] From an environmental standpoint, any activity causing significant surface disturbance, in need of a federal permit, is likely to also trigger these consultation requirements.

## § 29:42 Historic Preservation

Congress has determined that it is in the public's best interest to preserve the historical heritage of this country. In furtherance of this policy, Congress enacted the National Historic Preservation Act (NHPA)[1] which affirmatively requires all federal agencies approving any federal undertaking and prior to the issuance of any license to "take into account the effect of the undertaking on the district, site, building, structure, or object that is included in or eligible for inclusion in a national register (i.e. historic resources) and shall provide the advisory counsel on historic preservation a reasonable opportunity to comment with regard to the undertaking."[2] Tribes typically each have their own Tribal Historic Preservation Officer (THPO) whose mission is to integrate cultural resource compliance into a comprehensive planning process.[3] The THPO coordinates and consults with other state-specific historical agencies, and may assume the functions of the State Historic Preservation Officer (SHPO) with respect to trust land, if certain qualifications are met.[4] The tribes' THPO agency will require strict compliance with the Native American Graves Protection and Act (NAGPRA),[5] NHPA, and NEPA, and will likely require operators to pay for a cultural resource inventory along any ground disturbance routes.

Under NHPA, the federal government is required to consult with federally recognized Indian tribes whenever an undertaking has the potential to cause adverse effects to culturally or religiously significant properties.[6] Because the consultation requirements are government-to-government, oil and gas developers do not consult with the tribe directly. Consultations with the THPO and conducting an archeological resource survey will likely be required prior to commencing operations under any lease or right-of-way on tribal or individually allotted trust lands.[7] Therefore, an oil and gas company should communicate with federal agencies directly to determine whether consultation has occurred or whether site visits/consultation should be set up with the THPO and SHPO. A company should keep thorough records of any attempt to consult with a tribe.

### B. TRIBAL JURISDICTION

## § 29:43 *Montana* line of cases determining jurisdiction

"Tribal jurisdiction" refers to the ability of a tribal government to exercise authority over a person or entity; generally speaking, this includes the power of a tribe to tax, regulate, or subject a person or entity to adjudication in its courts. Questions of tribal jurisdiction can be very complicated and have been the subject of many papers,

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[12] 54 U.S.C. § 306108.

**[Section 29:42]**

[1] Pub. L. No. 89-665, 80 Stat. 915 (1966), 54 U.S.C. §§ 300101 et seq.

[2] Attakai v. U.S., 746 F. Supp. 1395, 1405, 21 Envtl. L. Rep. 20433 (D. Ariz. 1990); 16 U.S.C. § 470F.

[3] 36 C.F.R. pt. 800 (2021).

[4] 54 U.S.C. § 302702.

[5] 25 U.S.C. §§ 3001 et seq.

[6] 54 U.S.C. § 302706.

[7] *See* 36 C.F.R. § 800.16 (2021). An undertaking, as defined as "a project, activity, or program funded in whole or in part under the direct or indirect jurisdiction of a Federal agency, including those carried out by or on behalf of a Federal agency; those carried out with Federal financial assistance; and those requiring a Federal permit, license or approval." 36 C.F.R. § 800.16 (2021).

presentations, and publications.[1] Tribal jurisdiction is determined by federal case law. While the United States Supreme Court has plainly stated that there is no tribal criminal jurisdiction over non-Indians,[2] determinations of civil jurisdiction require a complex analysis of multiple factors, including land status and contractual relationships with tribal members. The scope of any tribe's jurisdiction is limited by federal law.[3]

With respect to a tribe's civil and regulatory jurisdiction, the general rule established by the United States Supreme Court is that Indian tribes lack jurisdiction over non-Indians who come within their borders.[4] There are two exceptions to this general rule. First, "a tribe may regulate, through taxation, licensing, or other means, the activities of nonmembers who enter consensual relationships with the tribe or its members, through commercial dealings, contracts, leases, or other arrangements."[5] Second, "a tribe may . . . exercise civil authority over the conduct of non-Indians on fee lands within its reservation when that conduct threatens or has some direct effect on the political integrity, the economic security, or the health or welfare of the tribe."[6] Federal courts apply the first exception only where a sufficient nexus exists between the relationship and the conduct over which the tribe seeks to exercise jurisdiction. The second exception is limited to those circumstances directly impacting the tribe's ability to govern itself, or directly affecting the health and welfare of the tribe.

The question of whether a tribe may exercise civil jurisdiction over a non-Indian is a question of fact in each case. There are very few certainties in this analysis. One must start with the presumption that the tribe has no civil jurisdiction, and thereafter examine the specific facts of each case to determine whether tribal jurisdiction is warranted. The most common method by which non-Indians subject themselves to tribal jurisdiction is by entering into a consensual relationship (a contract) with a tribe or its members.[7]

Another key factor in determining the extent of tribal jurisdiction is land ownership. Federal courts are more likely to find tribal jurisdiction if the events at issue occurred on tribal or allotted trust lands. In many cases, this is due to the reasoning that the tribe's power to exclude a person from trust lands necessarily includes the lesser power to regulate a non-Indian's activities while on those lands. In general, a tribe's ability to regulate or tax non-Indian activities is most limited when the activities at issue are restricted to non-Indian owned fee lands.[8] On the other hand, non-Indian companies are most likely to be subject to tribal jurisdiction

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**[Section 29:43]**

[1] *See, e.g.,* Westesen, *From Montana to Plains Commerce Bank and Beyond: The Supreme Court's View of Tribal Jurisdiction over Non-Members*, 2 Natural Resources Development on Indian Lands 9-1 (Rocky Mt. Min. L. Found. 2011) *and sources cited therein*.

[2] Oliphant v. Suquamish Indian Tribe, 435 U.S. 191, 194, 98 S. Ct. 1011, 55 L. Ed. 2d 209 (1978).

[3] Iowa Mut. Ins. Co. v. LaPlante, 480 U.S. 9, 15, 107 S. Ct. 971, 94 L. Ed. 2d 10 (1987).

[4] Plains Commerce Bank v. Long Family Land and Cattle Co., 554 U.S. 316, 128 S. Ct. 2709, 171 L. Ed. 2d 457 (2008).

[5] Montana v. U. S., 450 U.S. 544, 101 S. Ct. 1245, 67 L. Ed. 2d 493 (1981).

[6] Montana v. U. S., 450 U.S. 544, 566, 101 S. Ct. 1245, 67 L. Ed. 2d 493 (1981) (citing Fisher v. District Court of Sixteenth Judicial Dist. of Montana, in and for Rosebud County, 424 U.S. 382, 386, 96 S. Ct. 943, 47 L. Ed. 2d 106 (1976)).

[7] *See, e.g.*, Gustafson v. Estate of Poitra, 2011 ND 150, 800 N.W.2d 842 (N.D. 2011).

[8] *Plains Com. Bank*, 554 U.S. at 328; *see also* Strate v. A-1 Contractors, 520 U.S. 438, 446, 117 S. Ct. 1404, 137 L. Ed. 2d 661 (1997).

when they conduct activities on tribal trust or individually allotted trust lands.[9]

Although land status is not purely dispositive, it often makes the difference in a federal court's determination between tribal jurisdiction and state or federal jurisdiction. Because of the General Allotment Act of 1887,[10] there are many acres of fee lands located within the boundaries of Indian reservations.[11] "[U.S. Supreme Court] cases have made it clear that once tribal land is converted into fee simple, the tribe loses plenary jurisdiction over it."[12] For example, based on the General Allotment Act, courts have stated that county and local governments may impose ad valorem taxes on fee lands within a reservation.[13]

Given this background, tribal attempts to regulate and tax operations limited to non-Indian fee lands or fee interests may be subject to challenge. The inclusion of tribal or individually allotted trust lands in oil and gas operations, however, would likely result in tribal jurisdiction over at least part of the oil and gas development. Whether the tribes' resulting power to regulate would extend to the entire development due to the partial inclusion of tribal or allotted trust tracts is an open question.

## § 29:44 *Montana* line of cases determining jurisdiction—Employment Requirements

In contemplating development on Indian lands, it is important to keep in mind that the tribes have enacted, and will enforce, many tribal laws relevant to operations within their boundaries. Oil and gas development on a reservation would likely be subject to a tribe's Tribal Employment Rights Office (TERO) requirements.[1] TERO primarily deals with tribal hiring preferences and fees. It may also address matters of business licensing and require nonmember companies to register with the agency prior to commencing operations on the reservation. TERO agencies often require initial license filings and compliance plans, and may impose fees on an operator's construction activities, in addition to preferential treatment for hiring of tribal contractors and tribal employees. Federal courts have upheld the establishment of tribal employment preferences based on the operator's consensual relationship with the tribe.[2] Questions have been raised, however, regarding the extent to which TERO regulations apply to non-Indian activities on non-Indian fee lands.[3] The *Montana* analysis, discussed above, is applicable to any such analysis. The applicability of TERO laws as well as other tribal agency requirements can be negoti-

[9]Merrion v. Jicarilla Apache Tribe, 455 U.S. 130, 102 S. Ct. 894, 71 L. Ed. 2d 21 (1982) (upholding tribal severance taxes on oil & gas production from tribal leases).

[10]24 Stat. 388, as amended, 25 U.S.C. §§ 331 et seq.

[11]*See* Atkinson Trading Co., Inc. v. Shirley, 532 U.S. 645, 648, 650 n.1, 121 S. Ct. 1825, 149 L. Ed. 2d 889 (2001).

[12]Plains Commerce Bank, 554 U.S. at 328; *see also* Brendale v. Confederated Tribes and Bands of Yakima Indian Nation, 492 U.S. 408, 430, 109 S. Ct. 2994, 106 L. Ed. 2d 343 (1989) (opinion of White, J., stating that the tribe has no authority itself, by way of tribal ordinance or actions in the tribal courts, to regulate the use of fee land).

[13]County of Yakima v. Confederated Tribes and Bands of Yakima Indian Nation, 502 U.S. 251, 254-255, 112 S. Ct. 683, 116 L. Ed. 2d 687 (1992); *see also* Goudy v. Meath, 203 U.S. 146, 149-150, 27 S. Ct. 48, 51 L. Ed. 130 (1906) (explaining that the General Allotment Act exposed allotted lands to state assessment and forced sale for taxes by allowing them to be alienated).

**[Section 29:44]**

[1]*See* Neil G. Westesen & Joshua B. Cook, *Fort Berthhold: A 'Real World' Indian Law Oil and Gas Development Case Study*, Indian Law and Natural Resources: The Basics and Beyond 13-1 (Rocky Mt. Min. L. Found. 2017).

[2]*See* FMC v. Shoshone-Bannock Tribes, 905 F.2d 1311, 53 Empl. Prac. Dec. (CCH) P 40020 (9th Cir. 1990); *see also* MacArthur v. San Juan County, 497 F.3d 1057, 1071-72 (10th Cir. 2007).

[3]*See* State of Mont. Dept. of Transp. v. King, 191 F.3d 1108 (9th Cir. 1999).

ated with a tribe as part of the lease acquisition process.

## § 29:45 *Montana* line of cases determining jurisdiction—Taxation

Assessing whether tribes or states have a right to tax oil and gas operations on Indian land is a complex issue and answers may vary based on land status, tribal status, or the extent to which the operator has subjected itself to tribal contracts. In general, tribes may tax severance of minerals under tribal leases.[1] A state may also tax severance of minerals under tribal leases when the state is providing services in the area.[2] This results in a "dual taxation" situation, where an operator is being taxed twice for the same activity.[3] Dual taxation can be fairly common when operating on trust lands and most courts will uphold the state's severance tax so long as the economic burden falls on the nonmember developer instead of the tribe.[4] Due to potential dual taxation liability, a prudent operator should consider alternatives to minimize overall tax burdens, including tax credits or other incentives for energy and mineral development on trust lands.[5]

When operating on fee lands within a reservation, tribal taxes can likely be avoided. Tribes commonly rely on the *Montana* exceptions to assert broad claims of authority across their reservation. Nevertheless, as demonstrated in *Big Horn Electric v. Adams*, federal courts are reluctant to allow tribes to tax non-Indian fee lands or rights of way, even when tribes assert that these exceptions are present.[6] The federal courts' reluctance to allow tribal taxation on non-Indian fee lands would likely extend to oil and gas operations.[7]

### C. STATE AND LOCAL AUTHORITY

## § 29:46 Generally

In general, a state may not regulate property or conduct of tribes or Indian mineral owners within a reservation.[1] State conservation boards can generally regulate the development of minerals on fee lands within Indian reservations. These regulatory agencies have little, if any, authority over trust lands, and may not enforce state spacing or pooling orders as to included trust lands.[2] The exercise of state authority may also be barred to the extent that it imposes an undue burden on

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**[Section 29:45]**

[1] *See* Merrion v. Jicarilla Apache Tribe, 455 U.S. 130, 152, 102 S. Ct. 894, 71 L. Ed. 2d 21 (1982); Kerr-McGee Corp. v. Navajo Tribe of Indians, 471 U.S. 195, 105 S. Ct. 1900, 85 L. Ed. 2d 200 (1985).

[2] Cotton Petroleum Corp. v. New Mexico, 490 U.S. 163, 182, 109 S. Ct. 1698, 104 L. Ed. 2d 209 (1989). A state may not tax the Indian royalty received under IMLA leases. *See* Montana v. Blackfeet Tribe of Indians, 471 U.S. 759, 105 S. Ct. 2399, 85 L. Ed. 2d 753 (1985).

[3] *See Cotton Petroleum*, 490 U.S. at 191–192.

[4] *Cotton Petroleum*, 490 U.S. at 191–192; *see also* Ute Mountain Ute Tribe v. Rodriguez, 660 F.3d 1177, 1200, 173 O.G.R. 127 (10th Cir. 2011) (State severance tax upheld despite limited services provided to the operator).

[5] SLADE, "*Mineral and Energy Development on Native American Lands: Strategies for Addressing Sovereignty, Regulation, Rights, and Culture*," 56 Rocky Mt. Min. L. Inst. 5A-1 (2010).

[6] Big Horn County Elec. Co-op., Inc. v. Adams, 219 F.3d 944 (9th Cir. 2000); *see also* Plains Com. Bank, 554 U.S. at 330.

[7] *See* Big Horn County Elec. Co-op., Inc. v. Adams, 219 F.3d 944 (9th Cir. 2000).

**[Section 29:46]**

[1] McClanahan v. State Tax Commission of Arizona, 411 U.S. 164, 168, 93 S. Ct. 1257, 36 L. Ed. 2d 129 (1973) (" '[T]he policy of leaving Indians free from state jurisdiction and control is deeply rooted in the Nation's history.' "); Oklahoma Tax Com'n v. Chickasaw Nation, 515 U.S. 450, 458, 115 S. Ct. 2214, 132 L. Ed. 2d 400 (1995).

[2] Assiniboine and Sioux Tribes of Fort Peck Indian Reservation v. Board of Oil and Gas Conserva-

tribal government, or, in the Supreme Court's words, "unlawfully infringes on the right of reservation Indians to make their own laws and be ruled by them."[3] Absent explicit congressional authorization, a state or local regulation is categorically preempted by federal law if the legal incidence of the regulation falls upon an Indian tribe or an individual Indian with respect to income arising, property located, or a transaction occurring within Indian country.[4] Where the legal incidence of a state or local regulation falls on non-Indian persons or entities, however, federal law does not categorically preempt the regulation. Instead, courts apply a flexible analysis that makes "a particularized inquiry must be made into the nature of the state, federal and tribal interests at stake, an inquiry designed to determine whether, in the specific context, the exercise of state authority would violate federal law."[5]

## D. LEASING, EXPLORATION, DEVELOPMENT, PRODUCTION

### 1. Leasing

### § 29:47 Standard Form Leases

The leasing process for tribal and allotted minerals is found in 25 C.F.R. Parts 211 and 212.[1] An oil and gas company seeking to lease tribal minerals should request that BIA offer an identified tract for leasing. Tribal leases for oil and gas must first be offered for sale at a public auction.[2] After consultation with the tribe, the Secretary will advertise the lease for sale at an appropriate rental rate and royalty.[3] The advertisement for public auction must provide that the "Secretary reserves the right to reject any and all bids."[4] If no satisfactory bid is received at the auction, then the company may enter into private negotiation with the Secretary.[5] Allotted leases for oil and gas can also be offered for sale at a public auction, or an individual allottee can request that the Secretary negotiate the lease on behalf of the allottee(s).[6] However, the lessee must receive consent from the majority of the allottees in each tract.[7] Once a company is awarded the lease, it has the option to post one bond for each lease, a $75,000 bond for all oil and gas leases in each state, or a $150,000 bond for full nationwide coverage of oil and gas leases.[8] While a practitioner should conduct careful review of the form lease and applicable regulations, there are several lease regulations that a potential lessee of trust minerals should be aware of:

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tion of State of Montana, 792 F.2d 782, 794 (9th Cir. 1986).

[3]Assiniboine and Sioux Tribes of Fort Peck Indian Reservation v. Board of Oil and Gas Conservation of State of Montana, 792 F.2d 782, 794 (9th Cir. 1986) (citing Williams v. Lee, 358 U.S. 217, 220, 79 S. Ct. 269, 3 L. Ed. 2d 251 (1959) and other cases).

[4]Oklahoma Tax Com'n v. Chickasaw Nation, 515 U.S. 450, 115 S. Ct. 2214, 132 L. Ed. 2d 400 (1995).

[5]White Mountain Apache Tribe v. Bracker, 448 U.S. 136, 100 S. Ct. 2578, 65 L. Ed. 2d 665 (1980).

**[Section 29:47]**

[1]25 C.F.R. §§ 211.1 to 211.58 (2021) (tribal minerals); 25 C.F.R. §§ 212.1 to 212.58 (2021) (allotted minerals).

[2]25 U.S.C. § 396b; 25 C.F.R. § 211.20(a) (2021).

[3]25 C.F.R. § 211.20(b) (2021).

[4]25 C.F.R. § 211.20(b)(2). The secretary will reject the highest bid if it is not "in the best interest of the tribe. 25 C.F.R. § 211.20(b)(6) (2021).

[5]25 U.S.C. § 396b.

[6]25 C.F.R. § 212.20(b) (2021). If the allotted lease is offered for public sale, the auction process is identical to that of the tribal lease. 25 C.F.R. § 212.20(b) (2021).

[7]25 U.S.C. § 2218(b).

[8]25 C.F.R. § 211.24 (2021); 25 C.F.R. § 212.24 (2021).

(1) BIA has set the minimum royalty rate at 16 $_2/_3$% and requires the lessee to pay an annual rental of at least $2.00 per acre.[9]
(2) A lease may not exceed 640 acres.[10]
(3) The standard lease term is for 10 years and so long thereafter as the oil and gas are produced in paying quantities.[11] A standard form lease does not contain a savings clause.[12] To halt production from the lease, a lessee should obtain a suspension of operations from BIA.[13]
(4) The lease will be segregated into separate leases when a portion of the lease is committed to a communitization agreement.[14]
(5) To assign the lease, the lessee must obtain BIA consent. An allotted lease may also contain consent-to-assign language.[15]

## § 29:48 Standard Form Leases—IMDA Minerals Agreements

The IMDA authorized tribes to enter into Minerals Agreements providing for "the exploration for, or extraction, processing, of, oil, gas . . . or other energy or nonenergy mineral resources . . . in which such Indian tribe owns a beneficial or restricted interest."[1] The regulations governing Minerals Agreements are found at 25 C.F.R. Part 225.[2] There is no form agreement or required terms, but a Minerals Agreement shall address 21 specified provisions, including, but not limited to: (1) duration of the agreement; (2) indemnity of the Indian Mineral Owner; (3) valuation, reporting, and accounting procedures; (4) bonding and insurance; (5) reclamation; and (6) dispute resolution.[3] The Indian mineral owner may seek assistance from the Secretary in negotiating the Minerals Agreement, but assistance is not required.[4] Allottees can also become parties to a tribal IMDA agreement.[5] After the parties submit an agreement to the Secretary, the Secretary must generally approve or disapprove the agreement within 180 days of submission or 60 days after compliance with federal environmental laws.[6] The tribe may withdraw its consent at any time prior to final approval from the Secretary.

### 2. Exploration, Development and Production

## § 29:49 Surface Use and Access Issues

Any company planning oil and gas operations within an Indian reservation must ensure access to and from the leasehold. This can be accomplished through several means, including statutory rights-of-way, public roads and highways, BIA roads, IMDA Agreements, and, in some circumstances, condemnation.

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[9] 25 C.F.R. § 211.41(b) (2021); 25 C.F.R. § 212.41(b) (2021).

[10] 25 C.F.R. § 211.27(a) (2021); 25 C.F.R. § 212.27(a) (2021).

[11] 25 C.F.R. § 211.27 (2021); 25 C.F.R. § 212.27 (2021).

[12] WEBSTER, *Mineral Development of Indian Lands: Understanding the Process and Avoiding the Pitfalls*, 39 Rocky Mt. Min. L. Inst. 2-1 (1993).

[13] 25 C.F.R. § 211.44(a) (2021); 25 C.F.R. § 212.44(a) (2021).

[14] 25 C.F.R. § 211.28(g) (2021); 25 C.F.R. § 212.28(g) (2021).

[15] 25 C.F.R. § 211.53 (2021); 25 C.F.R. § 212.53 (2021).

**[Section 29:48]**

[1] 25 U.S.C. § 2102(a).

[2] 25 C.F.R. §§ 225.20 to 225.40 (2021).

[3] *See* 25 C.F.R. § 225.21(b) (2021) for the full list of necessary provisions.

[4] 25 C.F.R. § 225.21(a) (2021).

[5] 25 U.S.C. § 2102(b); 25 C.F.R. § 225.20(b) (2021).

[6] 25 C.F.R. § 225.22(a) (2021).

The process for obtaining a statutory right of way can be found in 25 C.F.R. part 169.[1] A right-of-way applicant must obtain both tribal consent and the consent of individual landowners.[2] However, rights-of-way may be granted without landowner consent in the following circumstances: (1) the land is owned by more than one person, and the owners of a majority interest consent; (2) one or more owners are unlocatable but a majority of the owners that are locatable consent; (3) the heirs or devisees of the Landowner have not been determined; or (4) the owners are so numerous that it would be impracticable to obtain their consent.[3] The right-of-way application must also include a bond, insurance, or other form a security to cover annual rentals, damages, remediation costs, and other fees.[4]

The compensation paid for a right-of-way must be "not less than Fair Market value."[5] The BIA defers to the tribes in determining the fair market value of trust land.[6] Rights-of-way for oil and gas operations are granted for an initial term of 20 years and can be renewed up to a maximum term of 50 years.[7] If an operator goes beyond the scope of the right-of-way, it may be liable for trespass.[8]

An operator can also utilize state highways, local roads, and BIA roads to access the leasehold. State highways and local roads properly opened and established in Indian reservations may be used by the general public in the same manner as any other public road.[9] While BIA roads are owned and maintained by the BIA, they are also open for general public use.[10] However, public use of BIA roads may be restricted for certain public safety reasons.[11]

Another way to obtain access is through an IMDA Minerals Agreement. If an operator enters a Minerals Agreement with the tribe, the operator can negotiate surface access and use to the particular leasehold, including across adjacent land.[12] A Minerals Agreement can also apply to allotted lands and minerals if all landowners consent to the agreement.[13] However, if none of the other measures are available, an operator could seek condemnation of a right-of-way. Congressional authorization is necessary to exercise eminent domain over tribal trust lands.[14] This process involves Congress demonstrating an intent to abrogate applicable treaty rights and

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**[Section 29:49]**

[1]The regulations were "modernized" in 2016 through a Final Rule entitled Rights-of-Way on Indian Land, 81 Fed. Reg. 14976 (March 21, 2016).

[2]25 U.S.C. § 324; 25 C.F.R. § 169.107 (2021). In addition, a grantee must obtain landowner consent it can assign a right-of-way. 25 C.F.R. § 169.207 (2021).

[3]25 U.S.C. § 324; 25 C.F.R. § 169.107 (2021). In addition, a grantee must obtain landowner consent it can assign a right-of-way. 25 C.F.R. § 169.207 (2021).

[4]25 C.F.R. § 169.103 (2021).

[5]25 C.F.R. § 169.112 (2021). Fair market value is defined as "the amount of compensation that a right-of-way would most probably command in an open and competitive market."25 C.F.R. § 169.2 (2021).

[6]25 C.F.R. § 169.110 (2021). Tribes generally receive more than fair market value for rights-of-way across trust land. *See* Branch, *supra* note 4 and accompanying text.

[7]25 C.F.R. § 169.201 (2021).

[8]25 C.F.R. § 169.2 (2021).

[9]Branch, *supra* note 4 and accompanying text.

[10]25 C.F.R. § 170.114(a) (2021); *see also* Brendale v. Confederated Tribes and Bands of Yakima Indian Nation, 492 U.S. 408, 439, 109 S. Ct. 2994, 106 L. Ed. 2d 343 (1989); Benjamin Carrywater v. Rocky Mountain Regional Director, 38 IBIA 116 (Sept. 13, 2002).

[11]25 C.F.R. § 170.114(a) (2021).

[12]25 C.F.R. § 225.21 (2021).

[13]25 U.S.C. § 2102(b).

[14]*See* Branch, *supra* note 4 for a detailed summary on the condemnation process.

authorize suits against the United States.[15] Condemnation of allotted lands has been specifically authorized "for any public purpose."[16] Allotted lands are to be condemned under the laws of the state in which the land is located, but the action must be filed in federal district court because state and tribal courts do not have jurisdiction over such actions.[17]

### § 29:50 Surface Use and Access Issues—Royalty Reporting and Valuation

FOGRMA requires ONRR to develop "enforcement practices that ensure the prompt and proper collection and disbursement of oil and gas revenues to Indian lessors."[1] In 1988, ONRR promulgated the current Indian oil and gas valuation regulations.[2]

### § 29:51 Surface Use and Access Issues—Reporting

Each month, for oil and gas production on Indian lands, an operator must submit an Oil and Gas Operations Report (the "OGOR Report"), Form 4054, and the Report of Sales and Royalty Remittance, Form ONRR-2014 (the "Form ONRR-2014").[1] It is the responsibility of the operator to ensure that all of the information in the reports is accurate and, if an error is discovered in a previous report, to file an amended report within 30 days of discovery.[2] Failure to submit accurate reports or update inaccurate reports could result in ONRR assessing up to $1,288 per day in civil penalties.[3]

### § 29:52 Surface Use and Access Issues—Valuation

The Indian oil valuation regulations are codified at 30 C.F.R. Part 1206—Subpart B.[1] The key factor in determining the value of the oil is whether it is sold under an arm's length transaction. Most Indian leases contain a "major portion provision" that provides that the lessee must determine the value of oil based on the highest price paid or offered at the time of production "for the major portion of oil produced

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[15] *See e.g.*, State of Minnesota v. U.S., 305 U.S. 382, 59 S. Ct. 292, 83 L. Ed. 235 (1939); Lone Wolf v. Hitchcock, 187 U.S. 553, 23 S. Ct. 216, 47 L. Ed. 299 (1903); Oneida Indian Nation of N. Y. State v. Oneida County, New York, 414 U.S. 661, 678, 94 S. Ct. 772, 39 L. Ed. 2d 73 (1974); Nicodemus v. Washington Water Power Co., 264 F.2d 614 (9th Cir. 1959).

[16] 25 U.S.C. § 357.

[17] State of Minnesota v. U.S., 305 U.S. 382, 389-91, 59 S. Ct. 292, 83 L. Ed. 235 (1939); Fredericks v. Mandel, 650 F.2d 144, 147, (8th Cir. 1981).

**[Section 29:50]**

[1] 30 U.S.C. § 1701(b)(3).

[2] *See* 53 Fed. Reg. 1184-01, 1988 WL 278009 (F.R.) for the 1988 oil valuation regulations and 53 Fed. Reg. 1230-01, 1988 WL 278010 (F.R.) for the 1988 gas valuation regulations. These regulations have been revised several times since 1988. *See* the Indian Payor Handbook available at ONRR.gov for a more detailed summary of a lessee's reporting and valuation requirements.

**[Section 29:51]**

[1] *See* 30 C.F.R. § 1210.102 (2021); 30 C.F.R. § 1210.52 (2021).

[2] 30 C.F.R. § 1210.30 (2021).

[3] 30 C.F.R. § 1210.30 (2021); 30 C.F.R. pt. 1241 (2021).

**[Section 29:52]**

[1] 30 C.F.R. §§ 1206.50 to 1206.65 (2021). These regulations apply to all gas produced from tribal and allotted oil and gas leases, except for leases located on the Osage Indian Reservation. *See* 25 C.F.R. pt. 226 (2021)—Leasing of Osage Reservation Lands for Oil and Gas Mining.

from the same designated area for the same type of crude."[2] When oil is sold pursuant to an arm's length transaction, the value for royalty purposes is the higher of the gross proceeds or the Index-Based Major Portion (IBMP) value determined under 30 C.F.R. § 1206.54.[3] When oil is not sold under an arm's length transaction, the value is the greater of the proceeds received or paid in sales and purchases of like-quality oil produced in the same field or area or the IBMP price.[4] The regulations provide allowances for transportation costs incurred under arm's-length contracts.[5]

The Indian gas valuation regulations are codified at 30 C.F.R. Part 1206—Subpart E.[6] When gas is produced from a lease located in an index zone, the operator must pay royalty based on the Index price assigned to the specific area.[7] If an index-based method cannot be used, the royalty value is determined using the gross proceeds less any applicable allowances.[8] For processed gas, ONRR employs a "Dual Accounting" of tribal leases whereby royalty is to be paid on the greater of the value of the gas or the value of the products derived from gas.[9] In general, if gas from an Indian lease is processed, even when the gas is processed after it is sold, the lessee is required to calculate both the unprocessed and processed value of the gas, and to pay royalties based on the greater of the two values.[10] For unprocessed gas, ONRR may use the major portion price for gas in the same designated area to determine the value of the gas.[11] The lessee must bear all costs which are necessary to place the gas into a "marketable condition."[12] After the gas reaches a "marketable condition," a lessee may take allowances for transportation costs incurred under arm's-length contracts.[13]

## E. CONCLUSION

### § 29:53 Generally

This section has provided an overview of oil and gas development on tribal lands. The area is extremely complicated and a prudent developer must exercise the utmost caution in operating on any particular Indian reservation. Indian nations are independent sovereigns. Each reservation has its own history, codes, and conventions. The field of law governing legal relations on Indian reservations is never static, and rarely settled. Therefore, when contemplating oil and gas development on tribal lands, a developer must examine the law under each particular set of circumstances and should never assume rights not clearly granted by law or enforceable contract.

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[2] 30 C.F.R. § 1206.51 (2021).

[3] 30 C.F.R. § 1206.52(a) (2021).

[4] 30 C.F.R. § 1206.53 (2021).

[5] 30 C.F.R. § 1206.57 (2021).

[6] 30 C.F.R. §§ 1206.170 to 1206.181 (2021).

[7] 30 C.F.R. § 1206.172(d) (2021). "Index zone" is defined as "a field or an area with an active spot market and published indices applicable to that field or area that are acceptable to ONRR." 30 C.F.R. § 1206.171 (2021). ONRR publishes the index zones that are eligible for index prices in the Federal Register.

[8] 30 C.F.R. § 1206.174 (2021).

[9] *See* 30 C.F.R. § 1206.172(a) (2021) to determine how the price should be calculated.

[10] 30 C.F.R. § 1206.172 (2021).

[11] 30 C.F.R. § 1206.174(c)(2) (2021).

[12] 30 C.F.R. § 1206.174(h) (2021). "Marketable condition" has been interpreted by the Interior Board of Land Appeals to require the processed gas to meet the specifications for transporting gas on the mainline pipeline where the gas is actually sold. Encana Oil & Gas (USA), Inc., 185 IBLA 133 (2014).

[13] 30 C.F.R. § 1206.174(h) (2021).

# VI. STATE AND LOCAL GOVERNMENT REGULATION OF OIL AND GAS

## A. STATE REGULATION—IN GENERAL

### § 29:54 Early Era of Regulation

Although comprehensive federal environmental laws and land management laws govern certain aspects of oil and gas development, for the most part, state regulation controls the time, place, intensity, and manner of development on private lands. State conservation laws regulate oil and gas development activities to assure responsible production of oil and gas and to prevent the waste and environmental degradation that resulted from the unconstrained application of the *rule of capture*, and which characterized the oil and gas industry's early years. Today, expansive state regulatory frameworks control numerous aspects of oil and gas development which continue to evolve in response to new technologies, production techniques, and evolving public policies.

The rule of capture provides that "[t]he owner of a tract of land acquires title to the oil and gas which he produces from wells drilled thereon, though it may be proved that part of such oil or gas migrated from adjoining lands."[1] In its most absolute form, the rule allowed an owner to take any lawful means, whether or not motivated by malice, to increase its share from the common source of supply without fear of injunction or liability for conversion.[2] Although, in the most extreme cases of purposeless production, other mineral owners in the common pool successfully sued for common law waste,[3] for the most part the rule of capture left mineral owners in the same reservoir with only one remedy: to drill.[4] Thus, the rule of capture incentivizes a mineral owner of a tract of land, however small, to drill anywhere on the tract and in the maximum density in order to capture as much of the common resource as possible.[5] Relatively unconstrained by common law rules and unregulated, scholars at the time characterized the early era of oil and gas development as a period of "profligate drilling and tremendous physical waste."[6]

An early Supreme Court precedent established the constitutionality of state laws regulating production. In 1893, the Indiana General Assembly enacted a statute that made it unlawful to "allow or permit the flow of gas or oil . . . into the open air" for more than two days after "gas or oil shall have been struck in such well."[7] Following allegations that it had violated the statute, Ohio Oil Co. argued that enforcement of the statute unconstitutionally deprived Ohio Oil Co. of its right to produce oil, thus amounting to a denial of its Fourteenth Amendment due process.[8] On appeal, the Supreme Court of the United States upheld the Indiana statute,

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**[Section 29:54]**

[1] Hardwicke, *The Rule of Capture and Its Implications as Applied to Oil and Gas*, 13 Tex. L. Rev. 391, 393 (1935); *see also* Elliff v. Texon Drilling Co., 146 Tex. 575, 210 S.W.2d 558, 561-62, 4 A.L.R.2d 191 (1948) (quoting this language verbatim).

[2] *See* Hague v. Wheeler, 157 Pa. 324, 27 A. 714, 719 (1893); Kelly v. Ohio Oil Co., 57 Ohio St. 317, 49 N.E. 399 (1897).

[3] Louisville Gas Co. v. Kentucky Heating Co., 132 Ky. 435, 33 Ky. L. Rptr. 912, 111 S.W. 374, 375–77 (1908).

[4] *See* Barnard v. Monongahela Natural Gas Co., 216 Pa. 362, 65 A. 801 (1907); *see also* Kelly v. Ohio Oil Co., 57 Ohio St. 317, 49 N.E. 399 (1897).

[5] *See* Hague v. Wheeler, 157 Pa. 324, 27 A. 714, 719 (1893).

[6] *See* Williams, *Conservation of Oil and Gas*, 65 Harv. L. Rev. 1155 (1952); Kramer & Anderson, *The Rule of Capture—An Oil and Gas Perspective*, 35 Envt. L. 899, 900 (2005).

[7] *See* Ohio Oil Co. v. State of Indiana, 177 U.S. 190, 190-91, 20 S. Ct. 576, 44 L. Ed. 729 (1900) (quoting the relevant language of the 1893 statute in question).

[8] Ohio Oil Co. v. State of Indiana, 177 U.S. 190, 198–99, 20 S. Ct. 576, 44 L. Ed. 729 (1900).

holding that "a lessee's or landowner's right to capture oil or gas from the property is restricted by the duty to exercise that right without waste or negligence.[9] Consistent with this holding, a number of states enacted early conservation legislation to prevent spillage or venting into the atmosphere and to require the proper plugging of abandoned wells.[10]

By 1920, it was quickly becoming apparent to lawmakers that a piecemeal approach would be insufficient to prevent concerns such as depletion and the exhaustion of oil and gas resources, thus prompting the need for a more coordinated approach to these issues facing the industry.[11] President Calvin Coolidge's created the cabinet-level Federal Oil Conservation Board (FOCB) in 1924, to study problems in the oil industry.[12] Following months of deliberations, the FOCB concluded that overproduction was preventing the conservation of the nation's wasting oil reserves by promoting inefficient uses and by dissipating reservoir pressure.[13] Around the same time, legal, professional, and industry associations advocated for the use of federal unitization laws to promote the conservation of these oil reserves.[14] Although initially unreceptive, in 1929 the FOCB and other notable organizations endorsed federal unitization.[15] This prompted Governor William H. Murray of Oklahoma to call on other oil-producing states in 1931 to form the Oil States Advisory Committee (OSAC) in order to keep regulation of the petroleum industry at the state level.[16] In 1932, the OSAC formulated a bill that called for the formation of an interstate oil compact.[17] However, compact plans, as well as the OSAC itself, were halted by the passage of the National Industrial Recovery Act of 1933 (NIRA).[18] NIRA imposed "hot oil" laws which prohibited the production of oil in violation of a state's prorationing rules and implemented state-by-state quotas on monthly oil production.[19] In 1935, however, the Supreme Court of the United States invalidated NIRA as "an unconstitutional delegation of legislative power," reopening a pathway for a compact and for state regulation.[20] Despite this, by the conclusion of the 1930s, only Arkansas, California, Louisiana, Oklahoma, and Texas had enacted legislation to create oil and gas conservation agencies or delegate authority to existing agencies to

[9] Black's Law Dictionary 1938 (11th ed. 2019); For an analysis of parallels to the rule of capture in groundwater law, *see*, Schremmer, Pore Space Property, 2021 Utah L.Rev. 1 (2021).

[10] *See, e.g.*, 1901 Kan. Legis. Serv. Ch. 224, § 1 (West).

[11] *Oil and Gas Conservation*, 43 Harv. L. Rev. 1137, 1138–40 (1930).

[12] Murphy, *Tennessee and the Interstate Compact to Conserve Oil and Gas*, Tenn. L. Rev. 551, 551–552 (1946); *see also* Dep't. of Interior, Conservation in the Department of the Interior, *The States Act for Oil Conservation*, https://www.nps.gov/parkhistory/online_books/doi/interior-conservation/chap7.htm (last visited June 29, 2021); *see also* Oklahoma Historical Society, Interstate Oil Compact Commission, https://www.okhistory.org/publications/enc/entry.php?entry=IN032 (last visited June 29, 2021, 2020).

[13] *See* Blakely, *supra* note 194.

[14] Weaver, *The Politics of Oil and Gas Jurisprudence: The Eighty-Six Percent Factor*, 33 Washburn L.J. 492, 518 (1994).

[15] *See* Weaver, *The Politics of Oil and Gas Jurisprudence: The Eighty-Six Percent Factor*, 33 Washburn L.J. 492, 518 (1994) (stating that the American Institute of Mining and Metallurgical Engineers, the American Petroleum Institute, the American Bar Association, and the Midcontinent Oil and Gas Association joined in endorsing federal unitization laws).

[16] Oklahoma Historical Society, *supra* note 194.

[17] *See* Blakely, *supra* note 194.

[18] *See* Blakely, *supra* note 194.

[19] National Industrial Recovery Act, 73 P.L. 67, 48 Stat. 195, § 9(c) (1933).

[20] A.L.A. Schechter Poultry Corporation v. U.S., 295 U.S. 495, 542, 55 S. Ct. 837, 79 L. Ed. 1570, 97 A.L.R. 947 (1935).

regulate the industry and oil and gas production and exploration activities.[21]

## § 29:55 Interstate Oil and Gas Compact Commission

In 1935, Congress approved the creation of the Interstate Compact to Conserve Oil and Gas (IOC) for the purpose of "conserv[ing] oil and gas by the prevention of physical waste. . . from any cause."[1] The compact required signatory states to enact or continue enforcing conservation laws addressing wasteful practices and to enact stringent penalties for the waste of oil or gas, including denied access to commerce for violators.[2] In addition to coordinating state legislative efforts, the IOC also created a transboundary governing body comprised of one representative from each member state.[3] This group, originally designated as the Interstate Oil Compact Commission and now termed the Interstate Oil and Gas Compact Commission (IOGCC), ascertains and reports on "methods, practices, circumstances and conditions . . . for bringing about conservation and prevention of physical waste of oil and gas."[4] The compact vests the IOGCC with rulemaking powers and empowers it to make recommendations to the states regarding coordination of the states' respective police powers "to promote the maximum ultimate recovery from the petroleum reserves.[5] Since its creation, the IOGCC has drafted a number of model statutes,[6] including one in 1949 which first authorized creation of drilling units and require cost sharing.[7] This precipitated a wave of state legislative action to enact oil and gas conservation laws and marked the beginning of the modern conservation period.[8] Although initially only ratified by six states,[9] the compact now includes 31 member states encompassing nearly all domestic oil and gas production.[10]

### B. CONSERVATION STATUTES

## § 29:56 Interstate Oil and Gas Compact Commission—Purposes

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[21]Hardwicke, *supra* at note 183, at 420; Walker, Jr., *supra* note 215, at 380-8; *see also* Wilson, *Conservation Acts and Correlative Rights: Has the Pendulum Swung Too Far?*, 35 RMMLF-INST 18 (1989); *see also* Anderson, *Foreword: The Evolution of Oil and Gas Conservation Law and the Rise of Unconventional Hydrocarbon Production*, 68 ARK. L. REV. 231, 232 (2014); *see also Oil and Gas Conservation*, *supra* note 14, at 1138.

**[Section 29:55]**

[1]Interstate Oil Compact, 49 Stat. 939, 74 Pub. Res. 64, 74 Cong. Ch. 781, art. II (1935); *see* H.R.J. Res. 407, 74th Cong. (1935); *see also* Sullivan, *The History and Purpose of Conservation Law, Oil and Gas Conservation Law and Practice*, 18A RMMLF-INST 1-1, 1-17-18 (Sep. 1985).

[2]IOC, *supra* note 204, at art. IV.

[3]IOC, *supra* note 204, at art. VI.

[4]IOC, *supra* note 204, at art. VI.

[5]IOC, *supra* note 204, at art. VI.

[6]*See* Interstate Oil & Gas Compact Comm'n, *Model Statutes*, http://iogcc.ok.gov/Default.aspx?shortcut=model-statutes (last visited June 29, 2021).

[7]Walker, *Discussion L: A Model Oil and Gas Conservation Law*, 26 TUL. L. REV. 267, 270 (1952); Daily, *Rules Done Right: How Arkansas Brought its Oil and Gas Law into a Horizontal World*, 68 ARK. L. REV. 259, 260 (2015).

[8]*See* Colo. Rev. Stat. Ann. § 34-69-10-130; Wyo. Stat. Ann. § 30-5-101-28; *see also* Oil and Gas Conservation Law, Act of July 25, 1961, Pub. L. 825, No. 359 (codified at 58 Pa. Cons. Stat. §§ 401 to 419 (West 1996)).

[9]*See generally* Colo. Rev. Stat. Ann. § 34-69-10-130; Wyo. Stat. Ann. § 30-5-101-28; *see also* Oil and Gas Conservation Law, Act of July 25, 1961, Pub. L. 825, No. 359 (codified at 58 Pa. Cons. Stat. §§ 401 to 419 (West 1996)).

[10]*See* Interstate Oil & Gas Compact Comm'n, *Member States*, http://iogcc.ok.gov/member-states (last visited June 29, 2021) (map showing current membership in the Interstate Oil Compact); Nat'l Ctr. For Interstate Compacts, *Interstate Compact to Conserve Oil and Gas*, http://apps.csg.org/ncic/Compact.aspx?id=81 (last visited June 29, 2021).

Today, every oil and gas producing state has some form of conservation law.[1] These closely mirror the model act proposed by the IOC and are consistent with the public purposes first established in *Ohio Oil*: the prevention of waste and the protection of correlative rights.[2] Despite some variation on specific conservation regulations over the years, "the basic pattern is essentially the same."[3] These statutes create or designate an agency for administration of state conservation programs and establish the powers and duties of the agency to prevent waste, including underground waste, surface waste, economic waste, and the waste that results from production exceeding the current demand or the capacities of transportation or marketing facilities.[4]

Over time, the tactics employed by conservation agencies to prevent waste and protect correlative rights have undergone substantial change.[5] Early state conservation efforts focused on surface waste limitations, such as those addressing spillage,[6] flaring,[7] and manufacture of carbon black,[8] and economic waste restrictions, such as prorationing,[9] common purchase orders requiring ratable take, and, at times, minimum wellhead pricing.[10] Subsequent regulations, including those for setbacks, spacing, and pooling, focused more directly on underground waste.[11] Recently, a number of state legislatures have authorized their respective agencies to consider public safety, health, welfare, and environmental concerns in exercising their delegated authority.[12]

## § 29:57 Interstate Oil and Gas Compact Commission—Conservation Agencies

Thirty-eight states currently have some form of agency responsible for regulating

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**[Section 29:56]**

[1]Nancy Saint-Paul, *Summers, Oil and Gas*, § 4:2 (3rd ed., 2015).

[2]Walker, Jr., *Property Rights in Oil and Gas and their Effect Upon Police Regulation of Production*, 16 TEX. L. REV. 370, 377 (1938).

[3]Sullivan, *The History and Purpose of Conservation Law, Oil and Gas Conservation Law and Practice*, 18A RMMLF-INST 1-18 (Sep. 1985).

[4]*See Conservation of Natural Gas and the Federal-State Conflict,* Note, 64 COLUM. L. REV. 888, 891–92 (1964); Hardwicke, *Oil-Well Spacing Regulations and Protection of Property Rights in Texas*, 31 TEX. L. REV. 99, 107 (1952); *see also* Williams, *supra* note 183, at 1163–77; *see also* Kramer, *Compulsory Pooling and Unitization: State Options in Dealing with Uncooperative Owners*, 7 J. ENERGY L. & POL'Y 255, 276–78 (1986).

[5]*See* Anderson, *supra* note 203, at 244.

[6]*See, e.g.*, Green v. General Petroleum Corp., 205 Cal. 328, 270 P. 952, 60 A.L.R. 475 (1928); Helms v. Eastern Kansas Oil Co., 102 Kan. 164, 169 P. 208 (1917); Teel v. Rio Bravo Oil Co., 47 Tex. Civ. App. 153, 104 S.W. 420 (1907).

[7]*See, e.g.*, 1919 Wyo. Sess. Laws ch. 125, § 1.

[8]*See, e.g.*, Quinton Relief Oil & Gas Co. v. Corporation Com'n of State of Oklahoma, 1924 OK 217, 101 Okla. 164, 224 P. 156 (1924) (holding that the State of Oklahoma may prohibit the use of natural gas for the manufacture of carbon black under Okla. Stat. Ann. tit. 52, § 237 when deemed a "wasteful utilization" of the resource).

[9]*See, e.g.*, Tex. Nat. Res. Code § 85.053 (West 2019); Wash. Rev. Code Ann. § 78.52.270 (West 2020).

[10]2 Ernest E. Smith & Jacqueline Lang Weaver, TEXAS LAW OF OIL & GAS § 9.3(A) (2d ed. 2018).

[11]Patrick H. Martin & Bruce H. Kramer, *The Law of Pooling and Unitization*, ch. 5 (3d ed. 2017).

[12]*See, e.g.*, Alaska Stat. § 31.05.030(e) (2018); Ariz. Rev. Stat. Ann. § 27-515 (1995); Colo. Rev. Stat. § 34-60-102, 106(2)(d); Ky. Rev. Stat. Ann. § 353.500 (2003); Mich. Comp. Laws Ann. § 324.61501(q)(ii)(B) (defining surface waste to include damage to environmental values).

the conservation of each respective state's oil and gas resources.[1] Ten of these states have explicitly named these agencies as oil or gas conservation commissions or boards,[2] while others have created similar agencies under different names or empowered existing agencies to undertake these duties.[3] State oil and gas conservations statutes create conservation agencies,[4] and authorize such agencies to exercise reasonable and necessary rulemaking powers to promote the conservation of the state's natural oil and gas resources.[5]

As with other agency decisions, the rules and regulations promulgated by these oil and gas conservation agencies are entitled to considerable deference under state administrative procedure acts modeled after the federal Administrative Procedure Act (APA) and the Model State Administrative Procedure Act (MSAPA).[6] This

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**[Section 29:57]**

[1] Ala. Code § 9-17-3 (2020); Alaska Stat. Ann. § 31.05.005 (West 2020); Ariz. Rev. Stat. Ann. § 27-514 (West 2020); Ark. Code Ann. § 15-71-101 (West 2020); Cal. Pub. Res. Code § 3106 (West 2020); Colo. Rev. Stat. Ann. § 34-60-104 (West 2020); Fla. Stat. Ann. § 377.07 (West 2020); Ga. Code Ann. § 12-4-43-50 (West 2020); Idaho Code Ann. § 47-314 (West 2020); 225 Ill. Comp. Stat. Ann. 725/4 (West 2020); Ind. Code Ann. §§ 14-3-2-2 through 14-37-3-17 (West 2020); Iowa Code Ann. §§ 458A.4, 458A.6-7 (West 2020); Kan. Stat. Ann. § 74-623 (West 2020); Ky. Rev. Stat. Ann. § 353.565 (West 2020); La. Rev. Stat. Ann. § 36:358C (2020); Mich. Comp. Laws Ann. § 324.62505 (West 2020); Miss. Code Ann. § 53-1-17 (West 2020); Mo. Ann. Stat. § 259.070 (West 2020); Mont. Code Ann. §§ 2-15-3303; 82-11-124 (West 2020); Neb. Rev. Stat. Ann. § 57-904 (West 2020); Nev. Rev. Stat. Ann. § 522.040 (West 2020); N.M. Stat. Ann. § 70-2-4 (West 2020); N.Y. Envtl. Conserv. Law § 23-0305 (McKinney 2019); N.C. Gen. Stat. Ann. § 143B-293.1 (West 2020); N.D. Cent. Code Ann. § 38-08-04 (West 2019); Ohio Rev. Code Ann. § 1509.02 (West 2020); Ohio Rev. Code Ann. § 1509.36 (West 2020); Okla. Stat. Ann. tit. 17, § 51 (West 2020); Or. Rev. Stat. Ann. § 520.055 (West 2020); 58 Pa. Cons. Stat. Ann. §§ 404 to 409 (West 2020); S.C. Code Ann. § 48-43-30 (2020); S.D. Codified Laws § 45-9-1.1 (2020); Tenn. Code Ann. § 60-1-202 (West 2020); Tex. Nat. Res. Code § 81.051 (West 2019); Utah Code Ann. § 40-6-5 (West 2020); Va. Code Ann. §§ 361.13 to 14 (West 2020); Wash. Rev. Code Ann. § 78.52.040 (West 2020); W. Va. Code Ann. § 22C-9-4 (West 2020); Wyo. Stat. Ann. § 30-5-101(a)(ii) (West 2020).

[2] Alaska Stat. Ann. § 31.05.005 (West 2020) (creating the Alaska Oil and Gas Conservation Commission); Ariz. Rev. Stat. Ann. § 27-514 (West 2020) (creating the Arizona Oil and Gas Conservation Commission); Colo. Rev. Stat. Ann. § 34-60-104 (West 2020) (creating the Colorado Oil and Gas Conservation Commission); Ky. Rev. Stat. Ann. § 353.565 (West 2020) (creating the Kentucky Oil and Gas Conservation Commission); Idaho Code Ann. § 47-314 (West 2020) (creating the Idaho Oil and Conservation Commission); Mont. Code Ann. §§ 2-15-3303; 82-11-124 (West 2020) (creating the Montana Board of Oil and Gas Conservation); Neb. Rev. Stat. Ann. § 57-904 (West 2020) (creating the Nebraska Oil and Gas Conservation Commission); N.M. Stat. Ann. § 70-2-4 (West 2020) (granting concurrent jurisdiction over the conservation of oil and gas and prevention of waste to the New Mexico Oil Conservation Division and the New Mexico Oil Conservation Commission); W. Va. Code Ann. § 22C-9-4 (West 2020) (creating the West Virginia Oil and Gas Conservation Commission); Wyo. Stat. Ann. § 30-5-101(a)(ii) (West 2020) (creating the Wyoming Oil and Gas Conservation Commission).

[3] *See, e.g.*, Ala. Code § 9-17-3 (2020) (creating the State Oil and Gas Board of Alabama); Ark. Code Ann. § 15-71-101 (West 2020) (creating the Arkansas Oil and Gas Commission); Iowa Code Ann. §§ 458A.4, 458A.6-7 (West 2020) (granting oil and gas regulatory authority to the Iowa Department of Natural Resources and the director of that department); Okla. Stat. Ann. tit. 17, § 51 (West 2020) (granting the Oklahoma Corporation Commission the power to create an Oil and Gas Department under its jurisdiction and supervision); Tenn. Code Ann. § 60-1-202 (West 2020) (granting rulemaking and enforcement authority to the Tennessee Board of Water Quality, Oil and Gas); Tex. Nat. Res. Code § 81.051 (West 2019) (granting the Railroad Commission of Texas jurisdiction over oil and gas operations within the state).

[4] *See*, e.g., Colo. Rev. Stat. Ann. § 34-60-105 (West 2020); N.M. Stat. Ann. § 70-2-6 (West 2020); Okla. Stat. tit. 17, § 52 (West 2020); 58 Pa. Stat. Ann. § 405 (West 2020); Tex. Nat. Res. Code § 81.051 (West 2020); Wyo. Stat. Ann. § 30-5-104 (West 2020); MARTIN, THE JURISDICTION OF STATE OIL AND GAS COMMISSION OIL AND GAS CONSERVATION LAW AND PRACTICE, 18A RMMLF-Inst 3, 3-1, 3-4–3-5 (1985).

[5] Adams, Note, *Judicial Review of Determinations of Oil and Gas Conservation Agencies*, 18 Miss. L.J. 456, 456 (1947).

[6] *See* REVISED MODEL STATE ADMIN. PROCEDURE ACT (NAT'L CONFERENCE OF COMM'RS ON UNIF. STATE LAWS 2010). Pursuant to its own terms, the APA does not apply to state administrative agencies. Thus, a

deferential standard of review commonly provides that a reviewing court may set aside an agency decision only upon a finding that: the decision is arbitrary, capricious, or not in accordance with law; the agency has exceeded the scope of its statutory authority; the agency decision violates the state or federal constitution or denies a person of constitutional rights; or the agency decision was made upon unlawful procedure.[7]

## § 29:58 Interstate Oil and Gas Compact Commission—Spacing & Density

Prior to enactment of spacing and density regulations, wasteful and dangerous practices related to overdrilling proliferated throughout the oil and gas industry.[1] These practices depleted reservoir energy through over-production and contributed to safety concerns regarding the increased danger of fire or blowout due to the close spacing of wells.[2] In response, state legislatures enacted legislation regulating spacing between wells, setbacks from property lines, and authorizing conservation agencies to establish drilling density within fields.

One such rule, Rule 37 in Texas, demonstrates the function of spacing requirements and the balance between limiting over drilling while still protecting the property rights of mineral owners. As early as 1919, the Texas state legislature enacted waste prevention legislation, prompting the Railroad Commission of Texas (RRC) to promulgate the first statewide spacing regulation, Rule 37.[3] At the time of its passage, Rule 37 implemented a prohibition against drilling oil or gas wells closer than 300 feet apart and fewer than 150 feet from property lines.[4] These distances have been increased a number of times throughout the course of Rule 37's more than one hundred year history,[5] and the current version of this rule provides for a setback of 1200 feet between wells and 467 feet from any property line.[6] Since its amendment in 1933,[7] the rules has authorized the RRC to grant exceptions "where necessary either to prevent waste or to prevent the confiscation of property."[8] The Supreme Court of Texas has noted that the dominant purpose of this exception is to protect property rights by "guarantee[ing] the opportunity in each owner to recover his oil by providing an exception to a uniform spacing regulation that would otherwise prevent him from doing so."[9]

Today, 38 states have some form of state-wide spacing regulations in place to

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state agency's obligation to respond to a petition for rulemaking is governed by each state's respective administrative procedure act. 5 U.S.C. § 701(b)(1).

[7]Larsen v. Oil and Gas Conservation Commission, 569 P.2d 87, 92 (Wyo. 1977).

**[Section 29:58]**

[1]Harrison, *Regulation of Well Spacing in Oil and Gas Production*, 8 ALTA. L. REV. 357 (1970); *see also* Myers, *Spacing, Pooling and Field-Wide Unitization*, 18 MISS. L.J. 267 (1947).

[2]Harrison, *supra* note 233, at 357.

[3]Harrison, *Regulation of Well Spacing in Oil and Gas Production*, 8 ALTA. L. REV. 357 (1970); *see also* Myers, *supra* note 233, at 267; *see also* Summers, *Legal Rights Against Drainage of Oil and Gas*, 18 TEX. L. REV. 27, 33 (1939); *see also* Sylvester & Malmsheimer, *Oil and Gas Spacing and Forced Pooling Requirements: How States Balance Energy Development and Landowner Rights*, 40 U. DAYTON L. REV. 47, 49 (2015).

[4]Myers, *supra* note 233, at 267; *see also* Rowland, *supra* note 233, at 361.

[5]*See* Harrison, *Regulation of Well Spacing in Oil and Gas Production*, 8 ALTA. L. REV. 357 (1970).

[6]16 Tex. Admin. Code § 3.37(a)(1) (2020).

[7]Brown v. Humble Oil & Refining Co., 126 Tex. 296, 83 S.W.2d 935, 940, 99 A.L.R. 1107 (1935).

[8]Brown v. Humble Oil & Refining Co., 126 Tex. 296, 83 S.W.2d 935, 940, 99 A.L.R. 1107 (1935); *see also* Myers *supra* note 233, at 267; *see also* Rowland, *supra* note 233, at 363.

[9]*Brown v. Humble Oil & Refining Co.*, 83 S.W.2d at 944; *see also* Summers, *supra* note 235, at 35; *see also* Rowland, *supra* note 233, at 364.

conserve oil or gas and protect the correlative rights of adjacent landowners through the establishment of optimal well patterns.[10] Nevertheless, there is considerable variation among the optimal spacing patterns adopted by states.[11] Setbacks, those which specify the minimum distance that an oil or gas well may be drilled from a property boundary, are the most common of these requirements. Of the 38 states applying some type of spacing requirements, Idaho is the only state that does not specify a minimum distance from which a well can be drilled along property lines.[12] Oregon applies its property boundary setback requirements only to gas wells.[13] Comparatively, the number of states applying spacing rules to regulate the minimum distance between wells is considerably lower.[14] Only 23 of these states apply well spacing regulations to oil wells; in addition, Pennsylvania and Oregon apply their requirements only to gas wells.[15] The application and specified distance of setbacks in many states vary between oil and gas wells,[16] based on the depth,[17] and in rarer circumstances may establish separate setbacks from exploration (wildcat) wells[18] in untested formations or those associated with enhanced recovery operations.[19]

In addition to these setback requirements, most state conservation statutes impose density regulations that that set standards for establishing drilling and spacing units.[20] In most states, units are limited to "the maximum area that may be economically and efficiently drained by one well."[21] These too vary between states.[22] Some states merely require that the parcel encompass more than one acre of land before certain wells may produce,[23] whereas others require as much as 640 acres.[24] Most states require somewhere in between.[25] Density requirements may also vary based

[10]*See* Sylvester & Malmsheimer, *supra* note 235, at 55–57 (providing a table that illustrates the requirements imposed by well spacing rules on a state-by-state basis); *see also* 055-3 WYO. CODE R. § 3 (LexisNexis 2020).

[11]*Compare.*, Alaska Admin. Code tit. 20, § 25.055 (2020) (providing for well spacing of 1,000 feet for oil wells and 3,000 feet for gas wells), *with* Okla. Admin. Code § 165:10-1-21 (2020) (providing for well spacing of 600 feet for both oil and gas wells with a depth of 2,500 feet or more, and a separate spacing of 300 feet for both oil and gas wells with a depth of less than 2,500 feet).

[12]Idaho Code Ann. § 47-319 (West 2020).

[13]Or. Admin. R. 632-010-0230 (2020).

[14]*See* Sylvester & Malmsheimer, *supra* note 235, at 55–57.

[15]Or. Admin. R. 632-010-0230 (2020); 58 Pa. Stat. Ann. §§ 407, 507 (2020).

[16]*See, e.g.*, Iowa Admin. Code r. 561-17.16(458A) (2020); La. Admin. Code tit. 43, Pt. XIX, § 1905 (2020).

[17]*See, e.g.*, 2 Code of Colo. Regs. § 404-1:318(c) to (d) (2020); La. Admin. Code tit. 43, Pt. XIX, § 1905 (2020); Okla. Admin. Code § 165:10-1-21 (2020); Tenn. Comp. R. & Regs. 0400-52-04-.01 (2020).

[18]*See, e.g.*, 178-00-1 ARK. CODE R. § B-3(e) (LexisNexis 2020); N.M. CODE R. § 19.15.15.9(A) (LexisNexis 2020).

[19]*See, e.g.*, 178-00-1 ARK. CODE R. § B-3(g) (LexisNexis 2020); 62 Ill. Admin. Code 240.430(b) (2020); Mo. Code Regs. Ann. tit. 10, § 50-3.020 (2020); N.M. CODE R. § 19.15.15.13(A) (LexisNexis 2020); Okla. Admin. Code § 165:10-1-21 (2020).

[20]*See Sylvester & Malmsheimer*, *supra* note 235, at 55–57; *see also* Kuntz, *Statutory Well Spacing and Drilling Units*, 31 OKLA. L. REV. 344, 344 (1978).

[21]*See, e.g.*, Ohio Rev. Code Ann. § 1509.01(g) (West 2019); Mont. Code Ann. § 82-11-201(3) (West 2019); N.M. Stat. Ann § 70-2-17 (West 2020).

[22]*See Sylvester & Malmsheimer*, *supra* note 235, at 55–57.

[23]*See, e.g.*, Cal. Pub. Res. Code § 3608 (West 2020); Ohio Admin. Code 1501:9-1-04(E) (2020).

[24]*See, e.g.*, Ariz. Admin. Code § 12-7-107(D) (2020); Iowa Admin. Code r. 561-17.16(458A) (2020).

[25]*See, e.g.*, Iowa Admin. Code r. 561-17.16(458A) (2020); Mont. Admin. R. 36.22.702 (2020); N.M. CODE R. § 19.15.15 (LexisNexis 2020).

on the depth of the well,[26] the substance produced from said well,[27] or for enhanced recovery projects.[28]

In response to the proliferation of hydraulic fracturing and horizontal drilling, many state conservation agencies have increased both the size of spacing unit and density within the spacing units. Depending on the language of the conservation statutes, increases in density or the size of drilling units may require additional legislative approval. For instance, Louisiana's statutes formerly defined a drilling unit as "the maximum area which may be efficiently and economically drained by one well."[29] In *Gatti v. State Department of Conservation*, the Louisiana Court of Appeals found that the drilling statute did not authorize the State Department of Conservation's practice of approving multi-well drilling units for both conventional and unconventional development.[30] Although the opinion was later reversed on jurisdictional grounds,[31] the Louisiana Legislature then amended the statute to redefine a drilling unit as "the maximum area which may be efficiently drained by the well or wells designated to serve the drilling unit."[32] Other states have similarly adapted through approval of larger units to accommodate longer laterals,[33] development of specific rules—such as Colorado's special rules of the greater Wattenburg area—[34] and comprehensive drilling plans,[35] creation of overlying horizontal and vertical spacing units for in-fill development,[36] approval of stacked laterals,[37] and Texas' allocation well policy.[38]

State oil and gas conservation agencies have also enacted setbacks from occupied structures. Unlike well spacing rules designed to protect correlative rights, conservation agencies enact setback restrictions for the purpose of protecting the health, safety, and welfare of landowners and communities by establishing minimum distances between development and areas of human habitation such as homes and schools.[39] Like spacing rules, these vary significantly between states—with a minority of states like Montana having no setbacks, others establishing shorter setbacks of 500 feet,[40] and among the longest, in Colorado, creating setbacks of 2,000 feet.[41]

Conservation agencies may also grant variances in order to accommodate new

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[26]*See, e.g.*, Ohio Admin. Code 1501:9-1-04(E) (2020); Tenn. Comp. R. & Regs. 0400-52-04-.01 (2020).

[27]*See, e.g.*, Ariz. Admin. Code § 12-7-107(A) to (B) (2020); Iowa Admin. Code r. 561-17.16(458A) (2020); Tenn. Comp. R. & Regs. 0400-52-04-.01 (2020).

[28]*See, e.g.*, 62 Ill. Admin. Code 240.430(b) (2020); MO. CODE REGS. ANN. tit. 10, § 50-3.020 (2020).

[29]La. Rev. Stat. Ann. § 30:9(B) (2020).

[30]Gatti v. State ex rel. Dept. of Conservation, 2013-289 La. App. 1 Cir. 1/15/14, 2014 WL 3517548 (La. Ct. App. 1st Cir. 2014), writ granted, judgment rev'd, 146 So. 3d 541 (La. 2014), and writ granted, judgment rev'd, 146 So. 3d 196 (La. 2014) and writ granted, judgment rev'd, 146 So. 3d 540 (La. 2014) and writ granted, judgment rev'd, 146 So. 3d 540 (La. 2014) and writ granted, judgment rev'd, 146 So. 3d 541 (La. 2014).

[31]Gatti v. State ex rel. Office of Conservation, 146 So. 3d 196 (La. 2014).

[32]LA. STAT. ANN. § 30:9; Hall, *Single Well Spacing and Pooling: State Spacing and Jurisdiction over Conservation*, 2019 NO. 6 RMMLF-INST 12 (2019).

[33]2 Colo. Code Regs. § 318A (2015), allows wells within the Wattenberg to be located in the middle of a section in order to "mitigate conflicts between mineral rights developer and surface owners."

[34]2 Colo. Code Regs. § 404-1:216(a) (2015).

[35]Okla. Admin. Code § 165:5-7-6(g) (2020).

[36]Okla. Stat. Ann. tit. 52, sec. 87.1 (West 2020); Okla. Admin. Code § 165:5/7/6 (2020).

[37]Statewide Rule 86(f)(1), 16 Tex. Admin. Code § 3.86 (2020).

[38]Squibb, *The Age of Allocation: The End of Pooling As We Know It?*, 45 TEX. TECH L. REV. 929 (2013).

[39]Righetti, *The Incidental Environmental Agency*, 3 UTAH L. REV. 685 (2020).

[40]N.D. Cent. Code Ann. § 38-08-05 (West 2019); WYO. RULES & REGS. OIL GEN ch. 3, § 47(a).

development techniques and to prevent waste and protect correlative rights where development within standard drilling, setback, or density rules would be impracticable. All conservation statutes provide a process by which the applicable conservation agency, after notice and hearing, may grant exceptions to distance and density regulations on an individual or field-wide basis.[42] Although requirements vary, at a minimum most state conservation statutes require a showing that an exception is necessary to prevent waste or protect correlative rights.[43] In some states, the conservation agency is specifically authorized to grant an exception for purposes of environmental protection.[44] Among other considerations, state agencies may be authorized to consider, inter alia, the increase in burden or hazard involved with a properly spaced well,[45] the ability of that well to produce in paying quantities,[46] written consent from affected landowners,[47] or other "good cause" that may warrant an exception.[48]

## § 29:59 Interstate Oil and Gas Compact Commission—Pooling & Unitization

"Pooling" and "unitization" are perhaps the most significant tool conservation

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[41] 2 CODE OF COLO. REGS. 404-1-604 (December 2020) (effective January 15, 2021).

[42] Ala. Admin. Code r. 400-1-2-.02(2)(g) (2020); Ala. Code § 9-17-12(c) (2020); Alaska Admin. Code tit. 20, § 25.055(d) (2020); Ariz. Admin. Code § 12-7-107(D) (2020); 178-00-1 ARK. CODE R. § B-3(i) (LexisNexis 2020); Cal. Code Reg. tit. 14, § 1721.7 (2020); 2 Code of Colo. Regs. § 404-1:318(c) to (d) (2020); Fla. Admin. Code Ann. R. 62C-26.004(6) (2020); Ga. Comp. R. & Regs. 391-3-13.05(1) (2020); Idaho Admin. Code r. 20.07.02.330.06 (2020); 62 Ill. Admin. Code 240.420-430 (2020); 312 Ind. Admin. Code 29-13-6 (West 2020); Iowa Admin. Code r. 561-17.16(458A) (2020); Kan. Admin. Regs. § 82-3-108(c) to (d) (2020); Ky. Rev. Stat. Ann. § 353.620 (West 2020); La. Admin. Code tit. 43, Pt. XIX, § 1907 (2020); Mich. Admin. Code r. 324.301(4) (2020); 26-1 MISS. CODE R. § 1.9 (LexisNexis 2019); Mo. Code Regs. Ann. tit. 10, § 50-3.010(4) (2020); Mont. Admin. R. 36.22.702 (2020); 267 Neb. Admin. Code § 013.02 (2020); Nev. Admin. Code § 522.240 (2020); N.M. CODE R. § 19.15.15.13(B) (LexisNexis 2020); N.Y. Envtl. Conserv. Law § 3-0503(3) (McKinney 2020); 15A N.C. Admin. Code §§ 1205 to 1206 (2020); N.D. Admin. Code 43-02-03-18.1 (2020); Ohio Admin. Code 1501:9-1-04(E) (2020); Okla. Admin. Code § 165:10-1-21 (2020); Or. Admin. R. 632-010-0235 (2020); 25 Pa. Code § 79.26 (2020); S.C. Code Ann. Regs. 121-8.9 (2020); S.D. Admin. R. 74:12:02:08 (2020); Tenn. Comp. R. & Regs. 0400-52-11-.01 (2020); 16 Tex. Admin Code § 3.37 (2020); Utah Admin. Code r. 649-3-3 (2020); 4 Va. Admin. Code § 25-160-60 (2020); Va. Code Ann. § 45.1-361.17 (2020); Wash. Admin. Code § 344-12-043-045 (2020); W. Va. Code R. § 39-1-4.3 (2020); 055-3 WYO. CODE R. § 3 (LexisNexis 2020).

[43] *See, e.g.*, Ariz. Admin. Code § 12-7-107(D) (2020) (waste only); Kan. Admin. Regs. § 82-3-108(c) to (d) (2020); La. Admin. Code tit. 43, Pt. XIX, § 1907 (2020); Okla. Admin. Code § 165:10-1-21 (2020); Mich. Admin. Code r. 324.301(4) (2020) (waste only); N.M. CODE R. § 19.15.15.13(B) (LexisNexis 2020); N.Y. Envntl. Conserv. Law § 3-0503(3) (McKinney 2020); N.D. Admin. Code 43-02-03-18.1 (2020); Ohio Admin. Code 1501:9-1-04(E) (2020); Tenn. Comp. R. & Regs. 0400-52-11-.01 (2020).

[44] *See, e.g.*, Cal. Code Reg. tit. 14, § 1721.7 (2020); 2 Code of Colo. Regs. § 404-1:318(c) (2020); Colo. Rev. Stat. Ann. § 34-60-104 (2020) (defining waste to exclude "the nonproduction of oil from a formation if necessary to protect public health, safety, and welfare, the environment, or wildlife resources as determined by the commission); Mich. Admin. Code r. 324.301(4) (2020); Ohio Admin. Code 1501:9-1-04(E) (2020); Or. Admin. R. 632-010-0235 (2020); 16 Tex. Admin Code § 3.37 (2020).

[45] *See, e.g.*, Ariz. Admin. Code § 12-7-107(D) (2020); 62 Ill. Admin. Code 240.420 (2020); Ky. Rev. Stat. Ann. § 353.620 (West 2020); 26-1 MISS. CODE R. § 1.9 (LexisNexis 2019); N.D. Admin. Code 43-02-03-18.1 (2020); S.D. Admin. R. 74:12:02:08 (2020); Wash. Admin. Code § 344-12-043-045 (2020).

[46] *See, e.g.*, N.D. Admin. Code 43-02-03-18.1 (2020); 25 Pa. Code § 79.26 (2020); S.D. Admin. R. 74:12:02:08 (2020); Wash. Admin. Code § 344-12-043-045 (2020).

[47] *See, e.g.*, 2 Code of Colo. Regs. § 404-1:318(c) (2020); Utah Admin. Code r. 649-3-3 (2020); Wash. Admin. Code § 344-12-043-045 (2020).

[48] *See, e.g.*, 2 Code of Colo. Regs. § 404-1:318(c) to (d) (2020); S.D. Admin. R. 74:12:02:08 (2020); Wash. Admin. Code § 344-12-043-045 (2020).

agencies use to protect correlative rights.[1] "Pooling" refers to "the bringing together of two or more small or irregularly shaped tracts of land to form a drill site in connection with a program of uniform well spacing," while "unitization" typically involves "a consolidation of a sufficient majority of the royalty and working interests in a geological pool that permits the reservoir engineers to plan operation of the pool as a natural energy mechanism."[2] Once combined, pooling or unitization permits operation of the pool or unit without regards to individual property boundaries and fractional interests, and establishes a method for allocation of production and costs associated with development.

Without pooling, density and spacing requirements would render many parcels undevelopable. Individual tracts may alone be smaller than the state's minimum acreage requirement for a spacing unit, but pooling allows an operator to combine interests within two or more tracts, or portions thereof, within a spacing unit to meet this requirement.[3] Owners within a pool equitably share expenses and production.[4] As a result, pooling prevents the drilling of unnecessary wells and protects the correlative rights of the owners of small tracks or portions thereof which would otherwise be undevelopable alone without a variance.[5] Spacing and pooling requirements are so linked that many conservation agencies will not issue a permit to drill unless interests within the spacing unit have been pooled.

A conservation agency may order pooling as part of either "voluntary pooling" or "compulsory pooling" processes.[6] In voluntary pooling, the owner of a mineral interest or its lessee, relying on authority within the oil and gas lease, voluntarily reaches agreement to pool the interest with the owners of other interests or tracts. If the parties do not reach a voluntary agreement to pool, the conservation agency may be able to force pool. Under compulsory pooling statutes, a state's conservation agency may,[7] or in some states must,[8] issue a pooling order at the request of an interested party for the purpose of preventing waste or protecting correlative rights. Notable outliers include Texas, which does not have compulsory pooling,[9] Pennsylvania, which allows compulsory pooling without a commission order,[10] and

**[Section 29:59]**

[1]King, *Pooling and Unitization of Oil and Gas Leases*, 46 Mich. L. Rev. 311, 312–13 (1948).

[2]*See* King, *supra* note 281, at 313.

[3]*See* Bruce M. Kramer, *Onshore Pooling and Unitization, Chapter 1 Principles and Historical Context of Pooling and Unitization*, 1-1 (Jan. 1997).

[4]*See* Keith B. Hall, *Federal Onshore Oil & Gas Pooling & Unitization—part 1, Chapter 11 Single Well Spacing and Pooling: State Spacing and Jurisdiction Over Conservation*, 11-6 to 11-10 (Oct 2014).

[5]*See* § 102; Smith, The Texas Compulsory Pooling Act, 43 Tex. L. Rev. 1003, 1009 (1965).

[6]*See* § 102; Smith, The Texas Compulsory Pooling Act, 43 Tex. L. Rev. 1003, 1009 (1965); *see also* King, *supra* note 281, at 317.

[7]*See, e.g.*, Alaska Stat. Ann. § 31.05.100(c) (West 2020); Ariz. Rev. Stat. Ann. § 27-505 (2020); Colo. Rev. Stat. Ann. § 34-60-116 (West 2020); Mont. Code Ann. § 82-11-202 (West 2019); Neb. Rev. Stat. Ann.§ 57-909 (West 2020); Nev. Rev. Stat. Ann. § 522.060(3) (West 2020); Utah Code Ann. § 40-6-6.5(2)(a) (West 2020); Wyo. Stat. Ann § 30-5-109(f) (West 2020).

[8]*See, e.g.*, Ala. Code § 9-17-13 (2020); Ark. Code Ann. § 15-72-303; Ind. Code Ann. § 14-37-9-1 (West 2020); Ky. Rev. Stat. Ann. § 353.630 (West 2020); N.D. Cent. Code Ann. § 38-08-08 (West 2020); Okla. Stat. Ann. tit. 52, § 87.1(e) (West 2020); 58 Pa. Stat. Ann § 408 (West 2020); Tex. Nat. Res. Code Ann. § 102.011 (West 2019).

[9]Some scholars have argued that the Mineral Interests Pooling Act may provide an avenue for forced pooling, *see*, Tex. Nat. Res. Code § 102.011; Vaughn, New Facets of Old Alternatives for Unleased Mineral Interests, 16 Tex. Wesleyan L. Rev. 113 (2009).

[10]58 Pa. Stat. and Cons. Stat. Ann. § 34.1 (West 2020).

Mississippi, which applies "judicial" or "equitable pooling."[11] Under Mississippi's "judicial pooling" regime, the land within a unit is pooled as a matter of law when a well is drilled within an existing spacing unit.[12]

Unitization involves field-wide, or partially field-wide, cooperation to promote efficient development of the underlying common reservoir.[13] Unitization has been characterized as "the ultimate conservation tool," because of its propensity to encourage the use of enhanced recovery methods and thereby increase the ultimate recovery that may be had from a particular reservoir.[14] Though more common on federal lands, a minority of states also authorize exploratory unitization to encourage orderly development in "one or more pools."[15] The 2004 Model Oil and Gas Conservation Act, developed by the IOGCC, includes provisions for exploratory unitization; however, it has not been adopted by all states.[16]

Like pooling, unitization may also occur on either a voluntary or compulsory basis.[17] In the context of voluntary unitization, working-interest and nonworking-interest owners must reach a unit operating agreement.[18] These agreements establish governance mechanisms and allocation formulas to equitably distribute production and costs within the unit.[19] Frequently, however, it is not possible to obtain unanimous consent to the unit operating agreement.[20] In these instances, many state statutes authorize the conservation agency to compel unitization, provided that a threshold percentage of interest owners—usually around 80%, consent.[21] When a field is compulsorily unitized, the state's conservation agency makes allocational and operational determinations after considering the correlative rights of owners within the unit.[22]

Courts have routinely upheld pooling and unitization statutes against constitutional challenges.[23] In one of the first cases, *Marrs v. City of Oxford,* the Eighth Circuit upheld local location, density, and pooling requirements as a constitutional exercise of police power concerning public safety and necessary to protect correlative

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[11]*See* Miss. Code Ann. § 53-3-7 (West 2020); *see also* Superior Oil Co. v. Foote, 214 Miss. 857, 59 So. 2d 85, 37 A.L.R.2d 415 (1952), error overruled, 214 Miss. 857, 59 So. 2d 844 (1952); *see also* Green v. Superior Oil Co., 59 So. 2d 100 (Miss. 1952).

[12]Miss. Code Ann. § 53-3-7 (West 2020).

[13]*See* Owen L. Anderson & Ernest E. Smith, *The Use of Law to Promote Domestic Exploration and Production*, 50 INST. ON OIL & GAS L. & TAX'N 2-1, 2-64 to 2-67 (1999).

[14]*See* Anderson & Smith, *supra* note 293; *see also* Owen L. Anderson, *Mutiny: The Revolt Against Unsuccessful Unit Operations*, 30 RMMLF-Inst. 13, 13-1, 13-3 to 13-8 (1984), (providing a brief overview of enhanced recovery methods, such as water flooding and carbon dioxide flooding).

[15]*See, e.g.* Wyo. Stat. Ann. § 30-5-110(c) (West 2020).

[16]IOGC 2004 Model Oil and Gas Conservation Act, Part VII at §§ 22-28 (http://www.iogcc.state.ok.us/docs/ModelAct-Dec2004.pdf); Pierce, *Minimizing the Environmental Impact of Oil and Gas Development by Maximizing Production Conservation*, 85 N. D. L. REV. 759, 766 (2009).

[17]*See* IOGC 2004 Model Oil and Gas Conservation Act, Part VII at §§ 22-28 (http://www.iogcc.state.ok.us/docs/ModelAct-Dec2004.pdf).

[18]*See, e.g.*, Alaska Stat. Ann. § 31.05.110 (West 2020); Nev. Rev. Stat. Ann. § 522.0824 (West 2020); N.D. Cent. Code Ann. § 38-08-09 (West 2019); *see also* Hardwicke, *Unitization Statutes: Voluntary Action or Compulsion*, 24 ROCKY MTN. L. REV. 29, 36 (1951).

[19]*See* Anderson, *supra* note 294.

[20]*See* Hardwicke, *supra* note 298, at 37 (providing a list of potential problems that may arise in the course of negotiating a unit operating agreement); *see also* Anderson, *supra* note 294.

[21]*See, e.g.*, Alaska Stat. Ann. § 31.05.110 (West 2020); Kan. Stat. Ann. § 55-1304 (West 2020); Nev. Rev. Stat. Ann. § 522.0824 (West 2020).

[22]*See, e.g.*, Mich. Comp. Laws Ann. § 324.61705 (West 2020); S.D. Codified Laws § 45-9-55 (2020).

[23]*See generally* Marrs v. City of Oxford, 32 F.2d 134, 67 A.L.R. 1336 (C.C.A. 8th Cir. 1929); *see also* Patterson v. Stanolind Oil & Gas Co., 305 U.S. 376, 59 S. Ct. 259, 83 L. Ed. 231 (1939).

rights.[24] Shortly thereafter, in *Patterson v. Stanolind Oil & Gas Co.*, the Supreme Court upheld a similar compulsory pooling law promulgated by Oklahoma's Corporation Commission.[25] Rejecting challenges based on the Due Process and Equal Protection Clauses of the Fourteenth Amendment, as well as under the Constitution's Contracts Clause, the Court upheld the Corporation Commission's use of statewide compulsory unitization statutes to effect proper drainage, achieve the greatest ultimate recovery of oil, conserve reservoir energy, and protect correlative rights.[26] In 1952, the Supreme Court rejected similar challenges to Oklahoma's 1941 statute authorizing the Corporation Commission to approve unitization plans.[27] Relying on its past decisions and the lack of a federal question, the court rejected arguments that the pooling statute was an unreasonable exercise of police power, an unreasonable delegation of legislative and judicial power, and the statute was too vague to provide guidance to the Commission's decisions.[28] A federal court in Colorado recently rejected a constitutional challenge to Colorado's forced pooling law on the basis that it violated owners due process rights, thus strengthening precedent on force pooling.[29]

## § 29:60 Interstate Oil and Gas Compact Commission—Economic Waste Restrictions

State conservation regulations may also limit economic waste.[1] Some of the earliest conservation efforts were aimed at preventing the unnecessary, inefficient, reckless, or uneconomic waste of oil and gas resources.[2] Indiana's 1893 law limiting venting of oil and gas was the first of these economic waste restrictions implemented by a state legislature, paving the way for future economic waste restrictions on useless or low value uses of production.[3] These included use of oil in inefficient manufacturing processes, for example the production of carbon black or lampblack, among others.[4] Today, some states' conservation statutes continue to prohibit excessive venting and flaring as the waste of gas.[5] In addition to preventing physical waste without a corresponding economic benefit, venting and flaring restrictions can also be environmentally beneficial by limiting the emissions of greenhouse gases (GHGs) and volatile organic compounds (VOCs) associated with oil and gas

[24] *See Marrs*, 32 F.2d at 135-37.

[25] *See Patterson*, 305 U.S. at 377–78.

[26] *Patterson*, 305 U.S. at 377.

[27] *See* Palmer Oil Corp. v. Amerada Petroleum, 343 U.S. 390, 391, 72 S. Ct. 842, 96 L. Ed. 1022 (1952).

[28] Palmer Oil Corp. v. Amerada Petroleum, 343 U.S. 390, 391, 72 S. Ct. 842, 96 L. Ed. 1022 (1952).

[29] Wildgrass Oil and Gas Committee v. Colorado, 447 F. Supp. 3d 1051 (D. Colo. 2020), judgment aff'd, 843 Fed. Appx. 120 (10th Cir. 2021).

**[Section 29:60]**

[1] Wells, *Please Give Us One More Oil Boom—I Promise Not to Screw It Up This Time: The Broken Promise of Casinghead Gas Flaring in the Eagle Ford Shale*, 9 TEX. J. OIL GAS & ENERGY L. 319, 325 (2014); Coleman, State Energy Cartels, 42 CARDOZO L. REV. __ (forthcoming Aug. 2021).

[2] *See* discussion *supra* Part [§ 29.55].

[3] *See* Ohio Oil Co. v. State of Indiana, 177 U.S. 190, 190, 20 S. Ct. 576, 44 L. Ed. 729 (1900) (quoting the relevant language of the 1893 statute in question).

[4] *See, e.g.*, Quinton Relief Oil & Gas Co. v. Corporation Com'n of State of Oklahoma, 1924 OK 217, 101 Okla. 164, 224 P. 156 (1924) (holding that the State of Oklahoma may prohibit the use of natural gas for the manufacture of carbon black under Okla. Stat. Ann. tit. 52, § 237 when deemed a "wasteful utilization" of the resource).

[5] *See, e.g.*, 225 Ill. Comp. Stat. Ann. 732/1-75(d)(4) (West 2020); N.D. Cent. Code Ann. § 38-08-06.4 (West 2019); *see also* Cal. Pub. Res. Code § 3300 (West 2020) ("[T]he blowing, release, or escape of gas into the air shall be prima facie evidence of unreasonable waste").

operations.[6]

Some conservation agencies are also authorized to use "proration units" to set "production allowables" to curtail economic waste by limiting production in excess of market demand and curtailing production rates.[7] In 1913, Oklahoma introduced the first laws limiting production to no more than "25% of the daily natural flow" and requiring wellhead metering of production for monitoring purposes.[8] Over the years, states have taken a variety of approaches to implement similar policies within their jurisdictions. Examples include laws designed to limit production to reasonable market demand, which require the state conservation agency to: (1) determine maximum allowable production at a statewide level; (2) determine each field's share of that production; and (3) establish an allocational formula that distributes this field allowable amongst the various owners.[9] Although some states do not explicitly recognize market-demand prorationing, at least once a court has found that the agency had implied authority and upheld prorationing in the name of waste prevention.[10] In contrast, however, many state legislatures have explicitly prohibited the use of market-demand prorationing.[11]

The Supreme Court has upheld state and proration statutes against constitutional challenges. In *Champlin Refining Co. v. Corp. Comm'n of State of Oklahoma*, the plaintiff argued that Oklahoma's proration statute constituted a violation of the Due Process and Equal Protection Clauses of the Fourteenth Amendment and it "operates to burden interstate commerce" in violation of the Commerce Clause.[12] Rejecting both arguments, the court found that the right to take oil is "subject to the reasonable exertion of the power of the state to prevent unnecessary loss, destruction, or waste."[13] The Court further held that prorationing laws "apply only to production and not to sales or transportation of crude oil or its products" and therefore do not affect interstate commerce, even if the products are actually shipped in such commerce.[14]

## § 29:61 Regulating to Prevent Environmental Damage

In recent years, some states and courts have begun to shift oil and gas conservation law towards assuring environmental and wildlife protection, providing conser-

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[6]*See* Ehrman, *Lights Out in the Bakken: A Review and Analysis of Flaring Regulation and its Potential Effect on North Dakota Shale Oil Production*, 117 W. VA. L. REV. 549, 560–62 (2014); *see also* Thomas, *Capping the Flame: Solving North Dakota's Natural Gas Flaring Problem Through Cap and Trade*, 8 GEO. WASH. J. ENERGY ENVTL. L. 137, 138–39 (2017).

[7]*See, e.g.*, N.M. Stat. Ann. § 70-2-17 (West 2020); Tex. Nat. Res. Code Ann. §§ 85.053, 85.054 (West 2019).

[8]*See* King, *supra* note 281; *see also* Ford, *Controlling the Production of Oil*, 30 MICH. L. REV. 1170, 1191 (1932) (quoting the applicable statute); *see also* discussion *infra* Part I.A.3.vi.

[9]*See, e.g.*, N.D. Cent. Code § 38-08-06 (West 2019); Tex. Nat. Res. Code § 85.053 (West 2019); Wash. Rev. Code Ann. § 78.52.270 (West 2020).

[10]*See* Lion Oil Refining Co. v. Bailey, 200 Ark. 436, 139 S.W.2d 683 (1940).

[11]*See, e.g.*, Colo. Rev. Stat. Ann. § 34-60-102(1)(b) (West 2020); Miss. Code Ann. § 53-1-1 (West 2020); Mont. Code Ann. § 82-11-305 (West 2019); Utah Code Ann. § 40-6-13 (West 2020); Wyo. Stat. Ann. § 30-5-204 (West 2020).

[12]*See generally* Champlin Refining Co. v. Corporation Com'n of State of Okl., 286 U.S. 210, 223-24, 235, 52 S. Ct. 559, 76 L. Ed. 1062, 86 A.L.R. 403 (1932).

[13]Champlin Refining Co. v. Corporation Com'n of State of Okl., 286 U.S. 210, 223–24, 233–34, 235, 52 S. Ct. 559, 76 L. Ed. 1062, 86 A.L.R. 403 (1932).

[14]Champlin Refining Co. v. Corporation Com'n of State of Okl., 286 U.S. 210, 223-24, 235, 52 S. Ct. 559, 76 L. Ed. 1062, 86 A.L.R. 403 (1932).

vation agencies with greater authority to consider environmental.[1] Colorado is the most explicit in this mandate. Colorado's 1994 amendments added numerous usages of the words "environment" and "environmental" to the state's Oil and Gas Conservation Act,[2] and limited to the Colorado Oil and Gas Conservation Commission's use of the Oil and Gas Environmental Response Fund to conditions causing "a significant adverse environmental impact on any air, water, soil, or biological resource."[3] The state's Oil and Gas Conservation Act was amended once again in 2007 to further require the commission to consider the impact of oil and gas operations on wildlife resources and to allow production within the state insofar as it is "consistent with the protection of public health, safety, and welfare, including protection of the environment and wildlife resources.[4] This Act was most recently amended in 2019, when language was added to require the promulgation of emissions control regulation by the Colorado Air Quality Control Commission "to minimize emissions of methane and other hydrocarbons, volatile organic compounds, and oxides of nitrogen from oil and gas exploration and production . . . ."[5] Moreover, the 2019 legislative changes explicitly pivoted the mission of the Colorado's Oil and Gas Conservation Commission towards one of environmental production, directing the agency to regulate, rather than promote, oil and gas production. In so doing, the amended Oil and Gas Conservation Act authorized the commission to consider cumulative and landscape scale environmental impacts, provided new opportunities for public input and consultation with other agencies, and redefined waste to exclude non-production where necessary to prevent damage to the environment.[6] Although no other state has yet pursued legislative amendments to this extent, Colorado may indicate an alternative direction for conservation law.

## C. OTHER STATE REGULATION

### § 29:62 Split Estate/Surface Damage Acts

In situations where the mineral estate is severed from the surface estate, otherwise known as a split estate, the mineral owner enjoys an implied right to use the surface to the extent reasonably necessary to develop the underlying minerals.[1] At common law, the mineral owner had no obligation to compensate the surface owner for damage or disruption resulting from its enjoyment of the dominant estate. Perhaps unsurprisingly, disputes frequently arise regarding access and use of the surface estate amongst the various owners.[2] State legislatures in a majority of oil and gas producing states have enacted statutes to address split estate disputes and

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**[Section 29:61]**

[1]*See, e.g.,* Colo. Rev. Stat. Ann. § 34-60-102(1)(a)(I) (West 2020) (providing that development and production of oil and gas in the state should be regulated "in a manner that protects public health, safety, and welfare, including protection of the environment and wildlife resources"); *see also* Mich. Admin. Code r. 324.301(4)(c) (2020) (providing that a spacing exception may be granted if the supervisor determines the exception "will prevent waste, protect environmental values, and not compromise public safety"); *see also* Or. Admin. R. 632-010-0235 (2020) (providing that a spacing exception may be granted for, inter alia, "environmental protection").

[2]*See* 1994 Colo. Legis. Serv. S.B. 94-177 (West).

[3]1994 Colo. Legis. Serv. S.B. 94-177 (West).

[4]1994 Colo. Legis. Serv. S.B. 94-177 (West).

[5]Colo. Rev. Stat. § 34-60-102(1)(I) (West 2020).

[6]Colo. Rev. Stat. § 34-60-103(11)(B) (West 2020).

**[Section 29:62]**

[1]*See* Lear & Barber-Renteria, *Split Estates and Severed Minerals: Rights of Access and Surface Use After the Divorce (and Other Leasehold Access-Related Problems)*, No. 1 RMMLF-Inst. Paper No. 12 (2005).

[2]Lear & Barber-Renteria, *Split Estates and Severed Minerals: Rights of Access and Surface Use*

allocate liability for certain categories of surface damages sustained in the course of oil and gas operations on split estates.[3] Even in states that have not enacted split-estate legislation requiring compensation, courts have developed doctrines requiring accommodation or otherwise limiting the scope of the mineral owners use.[4]

Split estate or surface-damage statutes, as they are often informally called, most often include provisions relative to notice, compensation, reclamation, surveying, and dispute resolution. Many of these statutes require the mineral developer to provide notice to the surface owner prior to commencing drilling operations, and the procedures for providing such notice varies from state to state.[5] Typically, either in conjunction with this notice requirement or separately, these statutes require good faith negotiations between the surface owner and the mineral owner to reach a surface use agreement.[6] Often times, these statutes explicitly enumerate damages that obligate a developer to tender compensation to the surface owner.[7] Furthermore, these statutes commonly impose surface restoration obligations on the mineral developer.[8] Split-estate statutes often delegate enforcement to the oil and gas conservation agency in the state, which may integrate compliance with the statutes into permitting procedures.[9] For instance, in Wyoming a proposed operator must certify its compliance with the split estate statute as part of submitting an Application for Permit to Drill to the conservation agency.[10] Although the agency does not review surface use agreements or independently verify that the act's requirements have been met, incorporation of that requirement provides an avenue for surface owners and other mineral owners to protest the application and to later challenge issuance of the permit. Where surface and mineral owners cannot agree to damages, some states will allow the surface owner to bring a suit for compensation in court,[11] while others will allow such a determination through binding arbitration.[12] In addition, some states also provide a similar framework that a mineral owner must

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*After the Divorce (and Other Leasehold Access-Related Problems)*, No. 1 RMMLF-Inst. Paper No. 12 (2005).

[3]Ark. Code Ann. § 15-72-214, -216 to -219 (West 2020); Colo. Rev. Stat. Ann. § 34-60-127 (West 2020); Ky. Rev. Stat. Ann. § 353.595 (West 2020); Mont. Code Ann. §§ 82-10-501 to -511 (West 2019); N.M. Stat. Ann §§ 70-12-1 to -10 (West 2020) ("Surface Owners Protection Act"); N.C. Gen. Stat. Ann. §§ 113-420 to 113-425 (West 2020); N.D. Cent. Code Ann. §§ 38-11.1-01 to -10 (West 2020) ("Oil and Gas Production Damage Compensation Act"); Ohio Rev. Code Ann. §§ 1509.072, .32 (West 2020); Okla. Stat. Ann. tit. 52, §§ 318.2 to 318.9 (West 2020); Okla. Stat. Ann. tit. 52, §§ 318.21 to 318.23 (West 2020) ("Seismic Exploration Regulation Act"); S.D. Codified Laws §§ 45-5A-1 to -11 (2020); Tenn. Code Ann. §§ 60-1-601 to -608 (West 2020) ("Oil and Gas Surface Owners Compensation Act of 1984"); Utah Code Ann. §§ 40-6-20 to -21 (West 2020); W. Va. Code Ann. §§ 22-7-1 to -8 (West 2020); Wyo. Stat. Ann. §§ 30-5-401 to -410 (West 2020) ("Wyoming Split Estate Act").

[4]*See, e.g.*, Getty Oil Co. v. Jones, 470 S.W.2d 618, 53 A.L.R.3d 1 (Tex. 1971).

[5]*See, e.g.*, Ky. Rev. Stat. Ann. § 353.595(3) (West 2020); Mont. Code Ann. § 82-10-503 (West 2019); N.M. Stat. Ann § 70-12-5 (West 2020); N.C. Gen. Stat. Ann. § 113-420 (West 2020); N.D. Cent. Code Ann. § 38-11.1-04.1 (West 2020); Okla. Stat. Ann. tit. 52, § 318.3 (West 2020).

[6]*See, e.g.*, Mont. Code Ann. § 82-10-504 (West 2019); N.M. Stat. Ann § 70-12-5 (West 2020); N.C. Gen. Stat. Ann. § 113-420 (West 2020); N.D. Cent. Code Ann. § 38-11.1-08 (West 2020); Okla. Stat. Ann. tit. 52, § 318.3 (West 2020); Wyo. Stat. Ann. § 30-5-402(f) (West 2020).

[7]*See, e.g.*, N.C. Gen. Stat. Ann. § 113-421 (West 2020); Wyo. Stat. Ann. § 30-5-405 (West 2020).

[8]*See, e.g.*, Ky. Rev. Stat. Ann. § 353.595(7); N.C. Gen. Stat. Ann. § 113-421 (West 2020).

[9]*See, e.g.*, Wyo. Stat. Ann. § 30-5-406(a) (West 2020).

[10]Wyo. Stat. Ann. § 30-5-403 (West 2020).

[11]*See, e.g.*, N.C. Gen. Stat. Ann. § 113-421(c) (West 2020), Okla. Stat. Ann. tit. 52, § 318.5 (West 2020); W. Va. Code Ann. § 22-7-7 (West 2020); Wyo. Stat. Ann. § 30-5-406(c) (West 2020).

[12]*See, e.g.*, Tenn. Code Ann. § 60-1-107 (West 2020); W. Va. Code Ann. § 22-7-7 (West 2020).

comply with before conducting geophysical exploration on a split estate.[13]

## § 29:63 Industrial Siting

Authority for siting oil and gas and other energy operations may also be subject to industrial siting requirements. Some states have authorized a new or existing board, agency, or commission to be responsible for industrial siting,[1] while others have directly conferred authority to the state's oil and gas conservation agency.[2] Industrial siting regimes vary significantly between states. For instance, in Wyoming, the Wyoming Oil and Gas Conservation Commission regulates most oil and gas drilling locations; however, a permit from the state's Industrial Siting Council is required for projects exceeding a certain monetary amount, waste facilities, and any commercial wind or solar electric generation facilities regardless of size.[3] In contrast, West Virginia's industrial siting laws apply only to solid waste facilities and include siting, location, design, construction, installation, establishment, financial assurance, permitting, modification, operating, groundwater monitoring, and closure and post-closure care.[4]

## § 29:64 Induced Seismicity and Chemical Disclosure

State legislatures have also enacted laws and regulations to address issues related to hydraulic fracturing and fluid disposal, including induced seismicity and chemical disclosure regulations.[1] Induced seismicity statutes and regulations allow regulatory agencies to respond to earthquakes attributed to underground injection activities.[2] Subsurface injection activities can contribute to an increase in seismic events. For instance, Oklahoma historically averaged about 1.6 earthquakes of magnitude 3.0 or greater, but this number dramatically rose to 584 by 2015.[3] The Oklahoma Geological Survey has attributed this increase in seismic activity to subsurface injections of produced water.[4] In response to the increase in seismic activity, the Oklahoma Corporation Commission promulgated a regulation that imposes monitoring and reporting obligations regarding induced seismicity upon Class II wells within the state.[5] Other states have enacted similar laws and regulations which apply to wells regulated pursuant to Class II of the Underground Injec-

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[13] *See, e.g.*, Mont. Code Ann. §§ 82-1-101 to -111 (West 2019), Okla. Stat. Ann. tit. 52, §§ 318.21 to 318.23 (West 2020).

**[Section 29:63]**

[1] *See, e.g.*, Neb. Rev. Stat. Ann § 57-1401 to -1413 (West 2020).

[2] *See, e.g.*, N.M. Stat. Ann. § 70-2-12 (West 2020).

[3] Wyo. Stat. Ann. §§ 35-12-102, 106 (West 2020).

[4] W. Va. Code Ann. § 22-15-1 *et seq.* (West 2020).

**[Section 29:64]**

[1] *See* Keith B. Hall & Scott Anderson, *Chapter 2B Hydraulic Fracturing Impact Studies: Recent Highlights, Summaries, and Analysis*, WATER ACQUISITION AND MANAGEMENT FOR OIL & GAS DEVELOPMENT (2016); *see also* NATHAN RICHARDSON ET AL., RESOURCES FOR THE FUTURE, THE STATE OF STATE SHALE GAS REGULATION 1 (2013).

[2] *See* INTERSTATE OIL AND GAS CONSERVATION COMMISSION & GROUNDWATER PROTECTION COUNCIL, POTENTIAL INJECTION-INDUCED SEISMICITY ASSOCIATED WITH OIL & GAS DEVELOPMENT: A PRIMER ON TECHNICAL AND REGULATORY CONSIDERATIONS INFORMING RISK MANAGEMENT AND MITIGATION (2015); *see also* Hall & Anderson, *supra* note 347, at 2B-16.

[3] *See* Hall & Anderson, *supra* note 347, at 2B-16; *see also* RICHARD D. ANDREWS, OKLAHOMA GEOLOGICAL SURVEY, STATEMENT ON OKLAHOMA SEISMICITY (2015).

[4] *See* Andrews, *supra* note 349.

[5] *See* Okla. Admin. Code § 165:10-5-7(c)(5) (2020); *see also* Okla. Admin. Code § 165:10-5-1 (2020) (providing that "underground injection well" includes enhanced recovery injection wells, disposal wells,

tion Control (UIC) program, which regulates oil and gas fluid injection wells.[6] Some states only impose monitoring and reporting requirements,[7] while others authorize state regulatory agencies to deny, modify, suspend, or terminate injection permits if the proposed injection is likely to or found to induce seismicity.[8] Another type of induced seismicity mitigation measure comes in the form of using so-called "traffic light systems," which involves monitoring injection rates and pressures, as well as the surrounding area for evidence of seismic activity.[9] An operator will be given a "green light" to continue injecting if no seismic activity is detected, or if only low magnitude events are detected.[10] However, if seismic events of a higher magnitude are detected, the operator will be given a "yellow light," which allows injection to continue but the operator must take the necessary precautions to mitigate these risks.[11] Furthermore, if seismic events above an even greater threshold are detected, the operator will be given a "red light" and operations will be required to cease.[12]

Chemical disclosure statutes and regulations require operators to disclose certain chemicals used in the hydraulic fracturing process.[13] Requirements among chemical disclosure laws vary. Many states chemical disclosure regulations refer to the Occupational Safety and Health Administration (OSHA) material safety data sheets for minimum quantities required to be disclosed.[14] In addition, all states with chemical disclosure laws allow for exemptions to protect trade secrets when the chemicals are considered "confidential business information."[15] Some states require that additive volume and concentration be disclosed, and, in some case, operators must categorize their disclosures by additive type.[16] Wyoming's regulations also require prior approval from the State Oil and Gas Supervisor for the use of VOCs, such as benzene, toluene, ethylbenzene, and xylene, and the same regulation expressly prohibits the injection of these VOCs into groundwater.[17] Fifteen states imposed requirements on chemical disclosure between 2010 and 2012, exemplifying the rapid pace at which this area of law is evolving.[18]

## § 29:65 Review by Wildlife Agencies

Some states have also incorporated environmental and wildlife protection goals in

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storage wells, and simultaneous injection wells).

[6] *See, e.g.*, 16 Tex. Admin Code §§ 3.46(d), 3.9, 5.203 (2020).

[7] *See, e.g.*, Ill. Admin. Code tit. 62, § 240.796 (2020); Okla. Admin. Code § 165:10-5-7(c)(5) (2020).

[8] *See, e.g.*, 16 Tex. Admin Code § 3.46(d) (2020); Ohio Rev. Code Ann. § 6111.044 (West 2020).

[9] *See, e.g.*, Okla. Admin. Code § 165:10-5-7 (2020); *see also* Hall, *Induced Seismicity: An Energy Lawyer's Guide to Legal Issues and the Causes of Man-Made Earthquakes*, 61 RMMLF-Inst. 5, 5-20 (2015).

[10] Hall, *supra* note 355, at 5-21.

[11] Hall, *supra* note 355, at 5-21. (stating the above proposition and providing that these precautions include "some combination of reduced injection rates, reduced pressures, and increased monitoring for seismicity").

[12] Hall, *supra* note 355, at 5-21.

[13] *See* RICHARDSON ET AL., *supra* note 347, at 43-44; Gosman, *Reflecting Risk: Chemical Disclosure and Hydraulic Fracturing*, 48 GEORGIA L. REV. 83 (2013); *see also* Hall & Anderson, *supra* note 347, at 2B-22.

[14] RICHARDSON ET AL., *supra* note 347, at 44.

[15] *See, e.g.*, 2 Colo. Code Regs. § 404-1:205A (LexisNexis 2020); Mont. Code Ann. § 82-10-604 (West 2020); *see also* RICHARDSON ET AL., *supra* note 347, at 43.

[16] *See, e.g.*, 2 Colo. Code Regs. § 404-1:205A (LexisNexis 2020); Mont. Code Ann. § 82-10-604 (West 2020); *see also* RICHARDSON ET AL., *supra* note 347, at 43.

[17] Wyo. Rules & Regs. 055.0001.3 § 45 (West 2020).

[18] RICHARDSON ET AL., *supra* note 347, at 44.

the regulation of oil and gas operations,[1] conferring certain oil and gas regulatory authority to the state's Department of Environmental Quality (DEQ) or wildlife agency.[2] In 2007, Colorado passed the Colorado Habitat Stewardship Act of 2007 for the purpose of minimizing adverse impacts to wildlife resources that are affected by oil and gas operations.[3] Under this Act, the COGCC is required to consult with the Parks and Wildlife Commission and Division of Parks and Wildlife on decisions that impacts wildlife resources.[4] This consultation also involves the implementation of "best management practices and other reasonable measures to conserve wildlife resources."[5] Additionally, rulemaking powers having been conferred to the COGCC, which again must be accompanied by consultation with the Parks and Wildlife Commission, to establish standards for minimizing adverse impacts and to ensure for the proper reclamation of wildlife habitat during and following oil and gas operations.[6] Similarly, in Wyoming, executive orders have required agencies, including the Wyoming Oil and Gas Conservation Commission, to "prioritize the maintenance and enhancement" of sage grouse habitat consistent with the Greater Sage Grouse Management Plan through permit stipulations and changes to drilling and spacing units, among other measures.[7]

## D. COUNTY REGULATION

### § 29:66 Generally

Under local land use laws generally, counties have various types of authority to control or guide industrial activities. However, such control and guidance must be compliant with the respective enabling act standard and statutory allowance.[1] The lines get blurred when legislative actions result in co-existing dual, yet independent, authority by state conservation agencies and local governments as such authority relates to oil and gas operations.[2] This Section provides a general background on the applicability of county regulations to oil and gas operations as well as a specific look at Colorado Senate Bill 19-181, a national precedent-setting law governing county authority over oil and gas locations and siting within local government boundaries.[3]

### § 29:67 County Authority and Governance of Oil and Gas Operations

Local land use authority is typically derived from a state constitution or statutory enabling act that outlines the extent and scope of county authority.[1] It is important to understand how a county's jurisdiction over land use, and therefore oil and gas

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**[Section 29:65]**

[1] *See* discussion *supra* Part I.A.4.

[2] *See, e.g.*, Ark. Code Ann. § 15-72-219(b) (West 2020); Cal. Fish & Game Code § 1016 (West 2020).

[3] Colo. Rev. Stat. Ann. § 34-60-128(2) (West 2020).

[4] Colo. Rev. Stat. Ann. § 34-60-128(3) (West 2020).

[5] Colo. Rev. Stat. Ann. § 34-60-128(3)(c) (West 2020).

[6] Colo. Rev. Stat. Ann. § 34-60-128(3)(d) (West 2020).

[7] Wyo. Exec. Order No. 2019-3 (replacing prior orders 2015-4 and 2017-2), *Greater Sage Grouse Core Area Protection*, (August 21, 2019), *available at:* https://wgfd.wyo.gov/WGFD/media/content/PDF/Habitat/Sage%20Grouse/Governor-Gordon-Greater-Sage-Grouse-EO-2019-3_August-21-2019_Final-Signed_1.pdf.

**[Section 29:66]**

[1] C.R.S. §§ 29-20-101, et seq. (Colo. 2019).

[2] *See generally,* S.B. 19-181.

[3] S.B. 19-181, 72d Gen. Assemb., Reg. Sess. (Colo. 2019).

**[Section 29:67]**

[1] To the extent "home rule powers" may relate to a County, please see § 29:77 The state legal

operations generally, is derived.

Upon review of several state constitutions and statutes, it is helpful to point out the differences in the establishment of county authority as it applies to oil and gas operations. In Wyoming, for example, the state distinguishes between municipal corporations and corporations of a public charter, such as counties, townships, and school districts.[2] Cities and counties in Wyoming differ in the way they are created, the authority they possess, and in the functions they perform.[3] Under the Wyoming Constitution, "[a]ll cities and towns are . . . empowered to determine their local affairs and government as established by ordinance passed by the governing body, . . . subject . . . to statutes uniformly applicable to all cities and towns . . . ."[4] Since Wyoming's statehood, the legislature has controlled municipalities, granting whatever powers they have.[5] Wyoming municipalities are "creatures of the state" having no inherent powers and possessing only the powers granted to them by the legislature.[6] Counties, however, are a "political subdivision of the state," created to aid in the administration of government by enforcing state statutes and laws—and *not* enacting them.[7] "As an arm of the state, the county has only those powers expressly granted by the constitution or statutory law or reasonably implied from powers granted."[8] Unlike municipalities, the Wyoming Constitution does not grant counties the power to establish ordinances.[9] "Counties being created for purposes of government, and authorized to exercise to a limited extent a portion of the power of the state government, have always been held to act strictly within the powers granted by the legislative act establishing them." Accordingly, the statute is to them their fundamental law, and their power is only coextensive with the power thereby expressly granted, or necessarily or reasonably implied from its granted powers.[10]

Based on the foregoing, very few counties in Wyoming have regulations that apply to oil and gas. Johnson County, however, adopted a comprehensive land use plan in 2005 identifying oil and gas development as an industrial use.[11] The plan sets some general development criteria for future oil and gas exploration and production activities and establishes issues to address reasonable development criteria.[12] Douglas County's Unified Land Development Code has an "Oil and Gas Operations" section to "ensure the safety, preserve the health, promote the prosperity and improve the morals, order, comfort and convenience of the present and future residents of the City" and "to facilitate the development of oil and gas resources within the City, while mitigating potential land use conflicts between such develop-

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environment: home rule, preemption, and interpretation; *see also* Colo. Const., Art. XX and Art. XIV. Municipalities and counties that are not classified as "home rule" must abide by the authority granted through state statutes.

[2]Dunnegan v. Laramie County Com'rs, 852 P.2d 1138, 1141 (Wyo. 1993).

[3]Dunnegan v. Laramie County Com'rs, 852 P.2d 1138, 1141 (Wyo. 1993).

[4]Wyo. Const. Art. XIII, § 1.

[5]Stewart v. City of Cheyenne, 60 Wyo. 497, 154 P.2d 355, 360 (1944).

[6]K N Energy, Inc. v. City of Casper, 755 P.2d 207, 210 (Wyo. 1988).

[7]*Dunnegan*, 852 P.2d at 1142.

[8]*Dunnegan*, 852 P.2d at 1142.

[9]*See generally* Wyo. Const. Art. XII.

[10]Hyde v. Board of Com'rs of Converse County, 47 Wyo. 101, 109, 31 P.2d 75, 77 (1934).

[11]Johnson County Comprehensive Land Use Plan, Adopted April 19, 2005 http://www.johnsoncountywyoming.org/jcco/wp-content/uploads/2017/09/jc_land_use_plan_mar05.pdf (June 15, 2021).

[12]Johnson County Comprehensive Land Use Plan, Adopted April 19, 2005 http://www.johnsoncountywyoming.org/jcco/wp-content/uploads/2017/09/jc_land_use_plan_mar05.pdf (June 15, 2021).

ment and existing, as well as planned, land uses."[13]

Under the Utah Constitution, counties are recognized as subdivisions of the state and their powers are not enumerated.[14] The Constitution states that "[t]he Legislature shall by statute provide for optional forms of county government."[15] Section 17-53-223 of the Utah Code grants broad authority to counties to enact ordinances and make regulations "necessary for carrying into effect or discharging the powers and duties conferred by this title, and as are necessary and proper to provide for the safety, and preserve the health, promote the prosperity, improve the morals, peace, and good order, comfort, and convenience of the county and its inhabitants, and for the protection of property in the county," so long as they are not "repugnant to law."[16] Utah's Land Use, Development, and Management Act was modified in 2005 with the following additions in bold and deletions stricken: "municipalities may enact all ordinances, resolutions, and rules and may enter into other forms of land use controls and development agreements that they consider necessary or appropriate for the use and development of land within the municipality, including ordinances, resolutions, rules, restrictive covenants, easements, and development agreements governing uses, density, open spaces, structures, buildings, energy efficiency, light and air, air quality, transportation and public or alternative transportation, infrastructure, street and building orientation and width requirements, public facilities, and height and location of vegetation, trees, and landscaping, unless expressly prohibited by law."[17] As such, Uintah County ordinances provide that "gas and oil wells shall not be located closer than one thousand (1,000) feet to any dwelling unit, unless written permission is given by the owner of such dwelling unit."[18] The County also puts the "burden to provide sufficient evidence to the satisfaction of the county legislative body that the proposed activity will not pollute, clog, alter, impair, or diminish water flow through the Ashley Springs system" on any proponent of oil and gas excavation.[19] Davis County requires a permit to excavate natural resources.[20] Duchesne County has an ordinance addressing oil and gas drilling facilities and production with sundry provisions.[21]

In New Mexico, the Constitution grants broad authority to municipalities, including counties, stating, "[a] municipality which adopts a charter may exercise all legislative powers and perform all functions not expressly denied by general law or charter . . . . The purpose of this section is to provide for maximum local self-government. A liberal construction shall be given to the powers of municipalities."[22] Cities and counties "shall have and enjoy all rights, powers and privileges asserted in its charter not inconsistent with its general laws, and, in addition thereto, such rights, powers and privileges as may be granted to it, or possessed and enjoyed by cities and counties of like population separately organized."[23] "An incorporated

[13]Douglas, Wyoming Code of Ordinances Sec. 6.40.

[14]Utah Const. Art. XI, § 1.

[15]Utah Const. Art. XI, § 4.

[16]Utah Code Ann. § 17-53-223 (LexisNexis, Lexis Advance through May 1, 2021).

[17]2005 Bill Text UT S.B. 60.

[18]Uintah County, Utah Code of Ordinances Sec. 17.33.020 3-D-2.

[19]Uintah County, Utah Code of Ordinances Sec. 17.24.070.

[20]Davis County, Utah Code of Ordinances Section 14.12.040.

[21]Duchesne County, Utah Code of Ordinances Section 8-13-5-4 https://codelibrary.amlegal.com/codes/duchesnecountyut/latest/duchesneco_ut/0-0-0-3397#JD_8-13-5-4 (last visited June 15, 2021).

[22]N.M. Const. Art. X, § 6.

[23]N.M. Const. Art. X, § 4.

county may exercise . . . all powers granted to municipalities by statute."[24]

The governing body of a municipality and, by virtue of Article X § 5 of the New Mexico Constitution, incorporated counties may adopt regulations that are not inconsistent with the laws of New Mexico to effect or discharge the powers and duties conferred by law upon the municipality, and provide for the safety, preserve the health, promote the prosperity and improve the "morals, order, comfort and convenience" of its inhabitants.[25] Under this authority, Farmington's municipal code, for example, states, "[a]ll proposals for oil, gas, or thermal drilling shall be referred to the oil and gas and geologic and engineering hazards advisory commission for recommendation in accordance with the provisions of the Municipal Code."[26] Silver City requires that at the conclusion of drilling, sites "shall be restored in accordance with a restoration plan approved by the Community Development Director and designed to minimize adverse impacts to neighboring properties."[27]

### § 29:68 Oil and Gas Location and Siting Authority—Case Study: Colorado

In Colorado, a self-proclaimed "home rule" state, the legislature expressly provided that most land use decisions are driven by local governments and not the State:

(1) The general assembly hereby finds and declares that to provide for planned and orderly development within Colorado and a balancing of basic human needs of a changing population with legitimate environmental concerns, the policy of this state is to clarify and provide broad authority to local governments to plan for and regulate the use of land within their respective jurisdictions. Nothing in this article shall serve to diminish the planning functions of the state or the duties of the division of planning.

(2) The general assembly further finds and declares that local governments will be better able to properly plan for growth and serve new residents if they are authorized to impose impact fees as a condition of approval of development permits. However, impact fees and other development charges can affect growth and development patterns outside a local government's jurisdiction, and uniform impact fee authority among local governments will encourage proper growth management.[1]

As such, Colorado designates land use authority to local governments through various laws.[2] Counties are authorized to prepare master plans (or comprehensive plans) in order to prepare and plan for the physical surface development within their respective jurisdictions, including oil and gas operations.[3] Counties are also authorized to adopt local zoning regulations to promote the public health, safety, and welfare of residents.[4] County zoning is commonly used to ensure development does not occur in sensitive, highly populated or hazardous areas.[5] Counties can also identify, designate, and regulate areas and activities of statewide impacts such as

[24]N.M. Const. Art. X, § 5.

[25]N.M. Stat. Ann. § 3-17-1 (LexisNexis, Lexis Advance through chapter 14 of the First Regular Session of the 55th Legislature (2021)).

[26]Farmington, New Mexico Code of Ordinances Sec. 2.4.36.

[27]Silver City, New Mexico Code of Ordinances Sec. 3.3.1.W.5.

**[Section 29:68]**

[1]C.R.S. § 29-20-102(1), (2).

[2]*See* C.R.S. §§ 29-20-101, et. seq., Colorado's Local Government Land Use Control Enabling Act of 1974.

[3]C.R.S. §§ 30-28-106, 31-23-206.

[4]C.R.S. §§ 30-28-111, 31-23-301.

[5]C.R.S. §§ 30-28-111, 31-23-301.

natural resource development areas and development of new communities.[6] If such areas are identified, then the county is allowed to control and require permits for development within such areas.[7]

On April 16, 2019, Senate Bill 19-181 "Concerning Additional Public Welfare Protections Regarding the Conduct of Oil and Gas Operations, and, in connection therewith, Making an Appropriation" was made effective and applied to oil and gas operations in Colorado "occurring on or after the effective date of this act, including determinations of applications pending on the effective date."[8] The adoption of Senate Bill 19-181 substantially changed the historic separate authority of the Colorado Oil and Gas Conservation Commission ("Commission"), the state conservation agency, and County governance to a co-existing, dual authority over oil and gas operations—meaning that both the County and the Commission must issue an operator a permit prior to any conduct of oil and gas operations on a proposed location.[9] This the new law received national attention and has been heralded as one for the current federal administration to review and utilize as an example of a successful regulatory regime.

Senate Bill 19-181 changed the Commission's mission from one of "fostering" oil and gas development to one that mandates that the Commission "regulate development and production of the natural resources of oil and gas in the state of Colorado in a manner that protects public health, safety, and welfare, including protection of the environment and wildlife resources."[10] This change from "foster" to "regulate" has resulted in years of lengthy rulemaking proceedings by the Commission and Colorado Department of Public Health and Environment, as well as new regulations and ordinances at a County level.[11]

Senate Bill 19-181 also changed the governing authority over oil and gas operations to expressly allow local governments, including Counties, to regulate the use of the surface within its boundaries as such regulation relates to oil and gas operations.[12] Specifically, § 29-20-104(1)(g) and (h), C.R.S. provide:

> (1) . . . Each local government within its respective jurisdiction has the authority to plan for and regulate use of land by:
>
> (g) Regulating the use of land on the basis of the impact of the use on the community or surrounding areas;
>
> (h) Regulating the surface impacts of oil and gas operations in a reasonable manner to address matters specified in this subsection (1)(h) and to protect and minimize adverse impacts to public health, safety, and welfare and the environment . . . . For purposes of this subsection (1)(h), "Minimize adverse impacts" means, to the extent necessary and reasonable, to protect public health, safety, and welfare and environment by avoiding adverse impacts from oil and gas operations and minimizing and mitigating the extent and severity of those impacts that cannot be avoided. The following matters are covered by this subsection (1)(h):
>
> (I) Land use;
>
> (II) The location and siting of oil and gas facilities and oil and gas

[6] C.R.S. § 24-65.1-101.

[7] C.R.S. § 24-65.1-101.

[8] S.B. 19-181, § 19.

[9] S.B. 19-181, §§ 3, 4 and 6.

[10] C.R.S. § 34-60-102(1)(a)(I).

[11] C.R.S. § 34-60-102(1)(a)(I).

[12] C.R.S. § 29-20-104(1)(h).

locations, as those terms are defined in section 34-60-103(6.2) and (6.4);

(III) Impacts to public facilities and services;

(IV) Water quality and source, noise, vibration, odor, light, dust, air emissions and air quality, land disturbance, reclamation procedures, cultural resources, emergency preparedness and coordination with first responders, security and traffic and transportation impacts;

(V) Financial securities, indemnification, and insurance as appropriate to ensure compliance with the regulations of the local government; and

(VI) All other nuisance-type effects of oil and gas development; and

(i) Otherwise planning for and regulating the use of land so as to provide planned and orderly use of land and protection of the environment in a manner consistent with constitutional rights."[13]

Under this provision, a County now has the ability to regulate any oil and gas operation that affects the surface of land within its jurisdiction.[14] The County, however, must ensure that such regulations are "necessary and reasonable" under the legislative standard set forth in Senate Bill 19-181.[15] If the County's regulation of oil and gas operations fall outside of the mandates provided in § 29-20-104(1)(h) or the regulations are deemed by an applicable court of law to be unnecessary or unreasonable, then the County will have exceeded the scope of its authority under Senate Bill 19-181 and the enacted regulations will not apply.[16] In order for a County to implement the powers and authority granted by Senate Bill 19-181 under § 29-20-104(1)(h), the County has authority to: (a) inspect all facilities subject to local government regulations; (b) impose fines for leaks, spills and emissions, and (c) impose fees on operators or owners to cover the reasonably foreseeable direct and indirect costs of permitting and regulation and the costs of any monitoring and inspection program necessary to address the impacts of development and to enforce local government requirements.[17] Each of these sections in Senate Bill 19-181 work in tandem to provide Colorado counties with the newly allowed, express authority over locating and siting new oil and gas operations within their respective jurisdiction.[18]

## E. MUNICIPAL REGULATION

[13] C.R.S. § 29-20-104(1)(g), (h); *see also* Colorado Oil and Gas Conservation Commission 300 and 500 series rules at 2 CCR 404-1 (2021).

[14] Prior to the adoption of Senate Bill 19-181, the primary authority for regulating oil and gas operations was clearly within the realm of the Commission. *See generally,* 34-60-102, C.R.S. (2018); City of Longmont v. Colorado Oil and Gas Association, 2016 CO 29, 369 P.3d 573, 82 Env't. Rep. Cas. (BNA) 1509, 182 O.G.R. 210 (Colo. 2016); City of Fort Collins v. Colorado Oil, 2016 CO 28, 369 P.3d 586, 82 Env't. Rep. Cas. (BNA) 1549, 182 O.G.R. 227 (Colo. 2016).

[15] C.R.S. § 29-20-104(1)(h).

[16] C.R.S. § 29-20-104(1)(h).

[17] C.R.S. § 29-20-104(2)(a) to (c).

[18] As of the date of this publication, at least six Colorado Counties have either adopted new ordinances and regulations, or have revised existing regulations, to allow for the inclusion of Senate Bill 19-181's express local government authority over oil and gas operations into their respective codes. *See generally*, Adams County—https://www.adcogov.org/oil-and-gas-information; Arapahoe County—https://www.arapahoegov.com/597/Oil-and-Gas; Boulder County—https://www.bouldercounty.org/property-and-land/land-use/planning/oil-gas-development/; Broomfield County—https://broomfield.org/1820/Oil-and-Gas; Larimer County—https://www.larimer.org/planning/phase-ii-larimer-county-land-use-code/oil-gas-regulations-phase-ii-update; and Weld County—https://www.weldgov.com/Government/Departments/Oil-and-Gas-Energy. There have also been over 15 Colorado towns, cities or municipalities adopt new ordinances or revise existing oil and gas regulations.

## § 29:69 Municipal Regulation—Introduction

This Section explains why municipal governments often seek to regulate or otherwise control or influence oil and gas-related activities within their jurisdictions. It describes the potentially negative impacts municipal governments and their citizens confront with the introduction of oil and gas-related activities, and the methods municipal governments use to control or influence those activities to address their concerns. It also addresses some of the obstacles municipal governments confront that limit or thwart their efforts.

Some municipal governments hope to use their limited authority to attract oil and gas-related activities for the jobs and tax revenue they believe will follow. Others hope to control or influence oil and gas-related activities to protect their communities from the environmental and other harms that may accompany them. Either way, it is clear that municipal governments often seek to exert some measure of control or influence over the oil and gas-related activities that either seek to operate in their jurisdictions or are already operating there.

The methods or legal tools municipal governments might use to address their concerns vary according to the legal environment of the state, particularly the home rule and preemption environments, discussed below. They also may vary according to the focus of control over which the municipality seeks to exert authority. For example, the focus of control may be on the locations within a jurisdiction where oil and gas-related activities will (or will not) take place, or it may be on the safety or manner in which those activities may be conducted. It might also focus on issues not directly related to place or safety but pertaining instead to the local economy or the ability of the local government to carry out essential services.

Some local governments have enacted total bans on the use of hydraulic fracturing technology, while others have enacted bans on all fossil-fuel development.[1] If a local government cannot, or does not, ban either the use of hydraulic fracturing technology or the development of hydrocarbons, it may still attempt to control the location in which it finds oil and gas activities to be most appropriate; for example, in an industrial zone rather than a residential zone. A local government might use its traditional power of land use control to exclude oil and gas activities from land use zones in which they would be inappropriate, or confine them to occur in zones for which they are better suited.[2] Some local governments may allow these activities only with conditional use permits.[3]

In addition to using zoning authority to control the location of oil and gas activities, municipal governments may use ordinances to control how close oil and gas-related activities may be to potentially vulnerable locations.[4] Municipal governments might impose setback requirements to protect their citizens in schools and other buildings the municipal government deems vulnerable or at-risk from proxim-

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**[Section 29:69]**

[1]*See* Shaun A. Goho, at 7, citing Food & Water Watch, Local Actions Against Fracking, *available at* http://www.foodandwaterwatch.org/water/fracking/fracking-action-center/local-action-documents (last visited Feb. 6, 2021).

[2]*See In Re Morrison, Ohio*, where, while striking down Munroe Falls, Ohio's attempt to impose a local permit and other controls, a concurring Ohio Supreme Court Justice suggested that the proper local authority for local governments seeking to influence or control oil and gas-related decisions lay in the city's power over traditional land use controls.

[3]*See,* e.g. County of Ventura Resource Management Agency, *Oil and Gas Program*, https://www.vcrma.org/oil-and-gas-program (last visited June 22, 2021); *see,* e.g. Municipality of Murrysville, Pa. Mun. Code § 220-28 (2010), https://ecode360.com/11539700.

[4]*See, e.g.*, Natale v. Everflow E., Inc., 195 Ohio App. 3d 270, 2011-Ohio-4304, 959 N.E.2d 602, 180 O.G.R. 202 (11th Dist. Trumbull County 2011) (analyzing a nuisance claim for placing an offensive and odorous oil and gas tank on a property adjacent to the plaintiff's).

ity to oil and gas-related activities.[5] Municipal governments may also use setbacks to protect rivers, lakes, or other environmentally vulnerable locations.[6] Municipal governments may attempt to exercise many of these controls by enforcing their own local permit or hearing requirements on oil and gas-related activities.[7] For example, although the Supreme Court of Ohio ultimately rejected this effort, Monroe Falls, Ohio used its ordinance authority to attempt to control oil and gas activities within municipal limits.[8] Other cities attempt to use zoning authority to accomplish similar goals.[9]

In addition to using their regulatory authority to control the location and manner of oil and gas activities, some municipal governments may choose to address other potentially negative impacts of oil and gas-related activities; for example, noise and traffic concerns. Most municipal governments already have either specific noise level ordinances or nuisance ordinances that can serve a similar, but broader purpose.[10] To enforce those in a manner that does not discriminate against incoming or existing oil and gas-related activities could be an effective means of control.[11] Certainly, if these ordinances existed prior to the arrival of the oil and gas-related activities, the case for upholding them is strong.

With respect to traffic controls, local governments have authority to set and enforce speed limits and other traffic-related controls. Some local governments have entered into agreements, called Road Use and Maintenance Agreements, with incoming oil and gas developers to pay for new and improved roads built according to the needs of the incoming industry.[12]

## § 29:70 Impacts of Oil and Gas Activities on Local Jurisdictions

Local governments hope to be involved in decision-making regarding incoming or existing oil and gas-related activities because their communities and constituents feel the effects of these activities. Some communities are new to oil and gas develop-

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[5] *See, e.g.*, Robinson Tp., Washington County v. Com., 623 Pa. 564, 612, 695, 83 A.3d 901, 181 O.G.R. 102 (2013).

[6] *See* Robinson Tp., Washington County v. Com., 623 Pa. 564, 612, 695, 83 A.3d 901, 181 O.G.R. 102 (2013).

[7] *See, e.g.*, State ex rel. Morrison v. Beck Energy Corp., 143 Ohio St. 3d 271, 2015-Ohio-485, 37 N.E.3d 128 (2015); *see also, e.g.*, Huntley & Huntley, Inc. v. Borough Council of Borough of Oakmont, 600 Pa. 207, 964 A.2d 855, 168 O.G.R. 524 (2009); *see also, e.g.*, Tri-Power Resources, Inc. v. City of Carlyle, 359 Ill. Dec. 781, 967 N.E.2d 811, 84 A.L.R.6th 663 (App. Ct. 5th Dist. 2012); *see also, e.g.*, Association of Irritated Residents v. Department of Conservation, 11 Cal. App. 5th 1202, 1206-07, 218 Cal. Rptr. 3d 517 (5th Dist. 2017); *see also, e.g.*, Robinson Tp., Washington County v. Com., 623 Pa. 564, 83 A.3d 901, 181 O.G.R. 102 (2013).

[8] *See* State ex rel. Morrison v. Beck Energy Corp., 143 Ohio St. 3d 271, 2015-Ohio-485, 37 N.E.3d 128 (2015).

[9] Tri-Power Resources, Inc. v. City of Carlyle, 359 Ill. Dec. 781, 967 N.E.2d 811, 84 A.L.R.6th 663 (App. Ct. 5th Dist. 2012); *see also* Protect PT v. Penn Township Zoning Hearing Board, 220 A.3d 1174 (Pa. Commw. Ct. 2019), appeal denied, 233 A.3d 677 (Pa. 2020); *see also, e.g.*, City of Longmont v. Colorado Oil and Gas Association, 2016 CO 29, 369 P.3d 573, 82 Env't. Rep. Cas. (BNA) 1509, 182 O.G.R. 210 (Colo. 2016).

[10] Goho, *Municipalities and Hydraulic Fracturing: Trends in State Preemption*, 64 PLANNING & ENV'T L. 3, 4–6 (2012).

[11] *See* Goho, *Municipalities and Hydraulic Fracturing: Trends in State Preemption*, 64 PLANNING & ENV'T L. 3, 4–6 (2012).

[12] *See* Best Practices of Road User Maintenance Agreements Amongst Local Government Agencies in Ohio, Ohio Department of Transportation, *available at* http://www.dot.state.oh.us/groups/oril/projects/Pages/Best-Practices-of-Road-User-Maintenance-Agreements.aspx (last visited June 22, 2021), *see also* Ohio's Oil and Gas Industry Road Improvement Payments, Ohio Oil and Gas Association and Energy in Depth at 4 (2017) *available at* https://www.energyindepth.org/wp-content/uploads/2017/11/2017-Utica-Shale-Local-Support-Series-Ohios-Oil-and-Gas-Industry-Road-Payments.pdf.

ment, and the technologies required for shale development differ substantially from those used in the communities in which conventional oil and gas extraction has occurred.[1] These new technologies allow development to move from rural areas, which are accustomed to it, to some suburban and ex-urban communities, which are not.[2]

Regardless of whether local governments seek to promote, control, or limit incoming or existing oil and gas-related activities, there are several issues they face when these activities ultimately arrive. These issues fall broadly into the categories of environmental law, and also in the related areas of traffic, infrastructure, employment, housing, and social and economic concerns.[3] Some argue that municipal governments seek involvement in oil and gas-related decision-making, at least in part, because they are dissatisfied with the protections afforded by state and federal legal controls.[4]

### § 29:71 Impacts of Oil and Gas Activities on Local Jurisdictions—Environmental

With the coming of oil and gas-related activities, municipal governments face environmental concerns of various kinds, most pointedly regarding air pollution, and water use and pollution.

### § 29:72 Impacts of Oil and Gas Activities on Local Jurisdictions—Air pollution concerns

Air pollution concerns arise from various aspects of facility construction and facility operations. The types of facilities related to oil and gas production vary. For example, truck traffic, engines and compressors that run drilling rigs and other equipment, and flaring of excess gasses are all sources of air pollution. The air pollutants they emit varies, too, including volatile organic compounds, dust, methane, sulfur dioxide and nitrogen oxides.[1] Particulate air pollution—meaning various sizes of dust—can increase in the ambient air during the construction of the facility and also during its operation, especially deriving from traffic over local roads.[2] Increased truck traffic due to a new facility can also lead to increase exhaust emissions.[3] Methane emissions can occur at wellhead sites and during materials transfers, all concerning to local governments Even the outflow of brine can cause air pollutant emissions due to the nature of the brine itself and the pollutants it collects on its journey into and out of fractured wells.[4] For example, engines, compressors, venting,

**[Section 29:70]**

[1]Goho, *supra* note 10, at 3–9.

[2]Goho, *supra* note 10, at 3–9.

[3]Goho, *supra* note 10, at 3–9.

[4]Goho, *supra* note 10, at 3–9.

**[Section 29:72]**

[1]Goho, *supra* note 10, at 3–9.

[2]Goho, *supra* note 10, at 3–9; *see also* EARTHWORKS, *Sources of Oil and Gas Air Pollution*, *available at* https://www.earthworks.org/issues/sources_of_oil_and_gas_air_pollution/ (last visited June 22, 2021).

[3]Lesley Fleischman, et al., *Fossil Fumes: A Public Health Analysis of Toxic Air Pollution From the Oil and Gas Industry*, CLEAN AIR TASK FORCE 14 (2016), *available at* https://www.catf.us/wp-content/uploads/2016/06/CATF_Pub_FossilFumes.pdf.

[4]Mary Kang, *CO2, Methane, and Brine Leakage Through Subsurface Pathways: Exploring Modeling, Measurement, and Policy Options* (2014) (Ph.D. Dissertation, Princeton University).

and flaring all emit air pollutants which may be concerning for local governments.[5]

## § 29:73 Impacts of Oil and Gas Activities on Local Jurisdictions—Water-related concerns

Water-related concerns are multifaceted for local governments. They might be concerned about the volume of water necessary for hydraulic fracturing operations and/or with the method of disposal of the large amounts of used fracturing fluid, or the brine these operations generate. Fracturing operations use an enormous amount of clean, fresh water—millions of gallons for every fractured well.[1] Local governments may not want these large quantities drawn from local sources for fear they would quickly diminish them or divert them from local uses.

Shale oil and gas facility operators mix fresh water with chemicals and proppants to prepare it for effective use as injection fluid to fracture the shale and stimulate production at the well. Operators inject the fracturing fluid into the well at high pressure to create fissures in the shale rock layer that allow oil and gas to escape. The fluid, or brine, then reemerges from the well along with naturally occurring pollutants it collected on its journey, such as salts, metals, and radioactive materials.[2] How and where safely to dispose of the resulting fluid has long been a concern. Because it is no longer clean water, it cannot be discharged from whence it came. Operators have been working on developing and improving methods for cleaning and re-using the brine it in future fracturing operations,[3] but still often send it wastewater treatment facilities,[4] or to deep well injection disposal locations as allowed in some states.[5] Sometimes, when a well casing is not as it should be, it can crack or leak and cause oil, gas, or fracturing fluid to leak into groundwater.[6]

## § 29:74 Impacts of Oil and Gas Activities on Local Jurisdictions—Other concerns facing municipal governments

Noise is also a concern for municipal governments and their citizens at both the construction and operation stages of oil and gas operations.[1] They may seek to use regulatory authority to control it. Another area of concern is the potential negative impact oil and gas operations may have on the conditions of local roads. Increased road use due to construction and operation could cause deterioration of local roadways, which may not have been constructed to bear increased loads. There might be increased traffic congestion due to oil and gas facilities business operations

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[5] Fleischman, *supra* note 19, at 16-7.

**[Section 29:73]**

[1] Goho, *supra* note 10 (citing U.S. Dep't of Energy, Modern Shale Gas Development in the United States, A Primer 64 (2009)).

[2] Goho, *supra* note 10 (citing U.S. Dep't of Energy, Modern Shale Gas Development in the United States, A Primer 64 (2009)).

[3] *See* Timothy J. Drake, *Renewable Water: Cleaning Flowback, Brine and Produced Well Water for Reuse, Discharge and Disposal*, ONG MARKETPLACE 6-7 (May 2015).

[4] *Fracking Water: It's Just So Hard to Clean*, NATIONAL GEOGRAPHIC (Oct. 2013), *available at* https://www.nationalgeographic.com/environment/article/fracking-water-its-just-so-hard-to-clean.

[5] *See* Deep Injection Wells: How Drilling Waste Is Disposed Underground, State Impact Pennsylvania on National Public Radio, *available at* https://stateimpact.npr.org/pennsylvania/tag/deep-injection-well/#:~:text=Deep%20injection%20wells%20are%20also,drilling%2C%20including%20frack%20waste%20water.&text=Much%20of%20the%20frack%20water,which%20has%20more%20disposal%20wells.

[6] *Groundwater Protection in Oil and Gas Production*, AMERICAN GEOSCIENCES INSTITUTE (2018).

**[Section 29:74]**

[1] Goho, *supra* note 10, at 5.

and worker ingress and egress. There may be concerns surrounding enforcement of traffic laws.

Although employment-related concerns are not always the first to come to mind when oil and gas-related activities are coming to town, these issues are real. Incoming oil and gas industry jobs may take employees away from local employers. The added oil and gas industry jobs may be a net-positive for the area, if they pay well and if they stay. But, if they do not—both pay well and remain in the area, the ultimate situation is less positive. When non-oil and gas-related local employers lose employees, they may not survive, and when the oil and gas facilities leave, the other employers may no longer be in the area to re-hire the employees they lost. When industry, such as that related to oil and gas development, overtakes a local economy, it becomes more difficult for that economy to recover in the face of its eventual absence.[2]

Local jurisdictions may face upward pressure on housing costs resulting from the influx of temporary oil and gas industry workers.[3] Local governments, therefore, may be concerned about the ability of their permanent residents to find and retain reasonably priced housing. The increased temporary population may also cause concerns related to emergency response and social service loads.[4]

## § 29:75 Law-based obstacles to municipal control or influence of oil and gas-related decisions

Municipal governments face numerous barriers to their ability to influence or control oil and gas-related activities. This section will describe some of those barriers and the legal environments in which they operate. In particular, although many municipal governments appear to have authority to act on local concerns under the 'home rule' provisions in their state constitutions or enabling statutes, some state courts have interpreted these provisions in ways that prevent local jurisdictions from regulating in areas related to oil and gas-activities. The fundamental question here is whether a municipal government may enact and enforce ordinances that attempt to control or influence oil and gas-related activities, or the state has taken away that authority.

## § 29:76 The state legal environment: home rule, preemption, and interpretation

Many states include 'home rule' provisions in their state constitutions.[1] These provisions generally grant authority to municipal governments to enact ordinances on issues of local concern, particularly in the areas of public safety and welfare and local self-governance.[2] Some states grant home rule by statute rather than through

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[2]Goho, *supra* note 10, at 4, citing Headwaters Economics, Fossil Fuel Extraction as a County Economic Development Strategy: Are Energy-Focusing Counties Benefitting? 2-3 (2008), *available at* https://headwaterseconomics.org/energy/oil-gas/fossil-fuel-extraction/ (last visited June 24, 2021).

[3]*Impact on Property Values,* American Petroleum Institute (2017), https://www.api.org/-/media/Files/Oil-and-Natural-Gas/Hydraulic-Fracturing/Health-and-Community/Impact-on-Property-Values.pdf.

[4]*See* Horner, et al., *Water Use and Management in the Bakken Shale Oil Play in North Dakota*, 50 Env't Sci. & Tech. 3275 (2016); *see also Social Impacts of Oil and Gas Development on Eastern Montana Communities*, Montana Board of Crime Control (2013).

**[Section 29:76]**

[1]J. Jon D. Russell & Aaron Bostrom, *Federalism, Dillon Rule and Home Rule*, American City County Exchange 6 (Jan. 2016).

[2]*See generally* Robertson, *When States' Legislation and Constitutions Collide with Angry Locals: Shale Oil and Gas Development and Its Many Masters*, 41 WM. & MARY ENVTL. L. & POL'Y REV. 55

their constitutions.[3] This section does not attempt to catalog state constitutions' home rule provisions or grants of home rule authority by state legislation. Instead, it describes some examples of the circumstances municipal governments face when attempting to use regulatory authority to address the environmental and related concerns described above.

## § 29:77 State constitution-based home rule authority

An example of constitution-based home rule authority, the Ohio Constitution provides that "[m]unicipalities shall have authority to exercise all powers of local self-government and to adopt and enforce within their limits such local police, sanitary and other similar regulations, as are not in conflict with general laws."[1] This suggests that municipal governments should be able to enact ordinances to address the local concerns set forth above. But that is not the case in Ohio. The problem for Ohio municipal governments comes both in the form of state legislation and state court interpretation of its constitution's home rule amendment.

## § 29:78 Preemption by a general law of the state

Explaining its position, the Supreme Court of Ohio considered a municipal ordinance in which "the city of Canton . . . prohibited the placement or use of mobile homes as principal or accessory structures for residential use"[1] then amended its ordinances to include "manufactured homes" within the definition of "mobile homes," thus prohibiting their residential use.[2] Concurrently, the Ohio General Assembly enacted a statute purporting to preclude political subdivisions from "prohibiting or restricting the location of permanently sited manufactured homes in any zone or district in which a single-family home is permitted."[3] Canton challenged the state legislature's authority arguing that the state law was unconstitutional because it encroached on municipality home-rule power.[4]

The Supreme Court of Ohio established a three-part test to determine when state legislation takes precedence over a municipal ordinance.[5] "A state statute takes precedence over a local ordinance when (1) the ordinance is in conflict with the statute, (2) the ordinance is an exercise of police power, rather than of local self-government, and (3) the statute is a general law."[6] While the first two prongs of the test were not contested in the *Canton* case, under the third prong, the Court found this state statute was not a general law. The Court explained that "[t]o constitute a general law for purposes of home-rule analysis, a statute must (1) be part of a statewide and comprehensive legislative enactment, (2) apply to all parts of the state alike and operate uniformly throughout the state, (3) set forth police, sanitary, or similar regulations, rather than purport only to grant or limit legislative power of a munic-

(2016).

[3] *See, e.g.*, N.C. Gen. Stat. § 113-415.1; *see also*, e.g., 52 Okla. Stat. Ann. § 137.1.

**[Section 29:77]**

[1] Ohio Const. art. XVIII, § 3.

**[Section 29:78]**

[1] This codified under § 1129.11 of Canton's Codified Ordinances.

[2] Canton Ordinance 49/98 (amending Canton Codified Ordinances § 1123.57(b).

[3] *See* Ohio Rev. Code Ann. § 3781.184 (West 2019).

[4] *See* Ohio Const. art. XVIII, § 3.

[5] *See* Canton v. State, 95 Ohio St. 3d 149, 2002-Ohio-2005, 766 N.E.2d 963, 966 (2002) (holding modified by, Mendenhall v. Akron, 117 Ohio St. 3d 33, 2008-Ohio-270, 881 N.E.2d 255 (2008)).

[6] *See* Canton v. State, 95 Ohio St. 3d 149, 2002-Ohio-2005, 766 N.E.2d 963, 966 (2002) (holding modified by, Mendenhall v. Akron, 117 Ohio St. 3d 33, 2008-Ohio-270, 881 N.E.2d 255 (2008)).

ipal corporation to set forth police, sanitary, or similar regulations, and (4) prescribe a rule of conduct upon citizens generally." The Ohio Supreme Court held that the applicable sections of the state law violated the Ohio Constitution's home rule amendment because it was an improper attempt to limit Canton's home-rule powers.[7] So, in the *Canton* case, the Court upheld the local action because the state law did not qualify as a general law such that it could preempt the local action. This appears initially hopeful for the prospects of municipal home rule.

Still, even when it appears that local governments have home rule authority through a state constitution, interpretation of the state's home rule provision and state legislatures' commitment to enacting statutes that quality as 'general laws' can prevent municipal governments from regulating in the area of oil and gas regulation. For example, addressing home rule, conflict with state law, and express state preemption of local authority in the context of municipal regulation of oil and gas-related activities, the Ohio Supreme Court held Ohio's oil and law to be a general law preempting municipal regulatory authority. In State ex rel. Morrison v. Beck Energy Corp.,[8] Beck Energy Corporation (Beck Energy), an oil and gas developer, secured the state-required permit from Ohio's Department of Natural Resources to drill on private property in Munroe Falls, Ohio.[9] After Beck Energy had begun drilling, Munroe Falls issued a Stop Work Order as authorized under an existing ordinance and sought an injunction arguing that Beck Energy failed to comply with Munroe Falls' drilling, zoning, and construction ordinances. The Supreme Court of Ohio affirmed the judgment of the appellate court, which held that because the ordinances were in direct conflict with several sections of the *Ohio Revised Code*, a general law under the *Canton* test,[10] the state law preempted the local ordinances, which Munroe Fall could not enforce against Beck Energy.[11]

## § 29:79 Express preemption by state law

State statutes may preempt local control by expressly preempting the activities the local government hopes to control.[1] For example, in Ohio, the Ohio oil and gas law grants 'sole and exclusive' authority over all aspects of the locating, drilling, and operating of oil and gas wells to the Ohio DNR.[2] Because the local ordinance purported to act in an area over which the state statute explicitly exerted control for

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[7] *Canton*, 766 N.E.2d at 965.

[8] State ex rel. Morrison v. Beck Energy Corp., 143 Ohio St. 3d 271, 2015-Ohio-485, 37 N.E.3d 128 (2015) (holding that the ordinance was preempted by state law).

[9] State ex rel. Morrison v. Beck Energy Corp., 143 Ohio St. 3d 271, 273, 2015-Ohio-485, 37 N.E.3d 128 (2015).

[10] Under *Canton*, "[T]o constitute a general law for purposes of home-rule analysis, a statute must (1) be part of a statewide and comprehensive legislative enactment, (2) apply to all parts of the state alike and operate uniformly throughout the state, (3) set forth police, sanitary, or similar regulations, rather than purport only to grant or limit legislative power of a municipal corporation to set forth police, sanitary, or similar regulations, and (4) prescribe a rule of conduct upon citizens generally." 766 N.E.2d at 968.

[11] *Beck Energy*, 989 N.E.2d at 280.

**[Section 29:79]**

[1] Natale v. Everflow E., Inc., 195 Ohio App. 3d 270, 2011-Ohio-4304, 959 N.E.2d 602, 605, 180 O.G.R. 202 (11th Dist. Trumbull County 2011) (holding that the ordinance in question was preempted by state law because it dealt with the "location and operation of the oil and gas well," which was explicitly reserved for the Ohio Department of Natural Resources in the state statute).

[2] "The regulation of oil and gas activities is a matter of general statewide interest that requires uniform statewide regulation, and this chapter and rules adopted under it constitute a comprehensive plan with respect to all aspects of the locating, drilling, well stimulation, completing, and operating of oil and gas wells within this state, including site construction and restoration, permitting related to those activities, and the disposal of wastes from those wells." Ohio Rev. Code. § 15.09.02.

itself, the state statute preempted the local ordinance.[3] One example is supplied by a Warren, Ohio ordinance that prohibited oil and gas well storage tanks from being located within two hundred feet of any building or structure without a local waiver. The Eleventh District Court of Appeals (Ohio) held that the preemption provision in Ohio's oil and gas law, Ohio Rev. Code § 1509.02 preempted Warren's ordinance because the ordinance purports to act on an issue the statute explicitly prohibits.[4]

### § 29:80 Operational conflict with state law

Colorado provides home rule authority by statute, rather than by Constitutional provision. The Colorado home rule statute states that "[e]ach local government within its respective jurisdiction has the authority to plan for and regulate the use of land . . . ."[1] However, the state also employs an operational conflict test which would void any local action that would materially impede or destroy a state interest.[2] For example, La Plata County, Colorado, enacted an ordinance that authorized the creation of a county planning commission to enact local zoning plans for unincorporated territory. Four years prior, Colorado had passed the Oil and Gas Conservation Act creating a state Oil and Gas Commission with jurisdiction over all persons and property in enforcing the rules and regulations set forth under the Act.[3] Oil and gas firms sued La Plata County. The Supreme Court of Colorado relied on Ray v. City & County of Denver, where it had held that while a county cannot adopt an ordinance that is in conflict with any state statute, stating that "an ordinance and a statute may both remain effective and enforceable as long as they do not contain express or implied conditions that are irreconcilably in conflict with each other." The Court considered the purpose of the ordinance at issue and found it to align with the state's interests, rather than impeding it.[4] Therefore, the Court concluded that there was no operational conflict between the state statute and the local ordinance.[5] Although the case illustrating the concept of operational conflict pertained to a county ordinance, the principles would likely hold true for conflict in municipal ordinances as well.

For example, and pertaining to oil and gas regulation, the Colorado Supreme Court held a city's hydraulic fracturing ban "[to be preempted because it] . . . materially impeded the effectuation of the state's interest" because it prohibited all fracking, including procedures allowed by the Colorado Oil and Gas Commission's

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[3] § 731.06 of the Codified Ordinances of Warren, Ohio.

[4] Smith Family Trust v. Hudson Bd. of Zoning & Bldg. Appeals, 2009-Ohio-2557, at ¶ 10, 2009 WL 1539065 (Ohio Ct. App. 9th Dist. Summit County 2009) ("[T]he test is whether the ordinance permits or licenses that which the statute forbids and prohibits, and vice versa.").

**[Section 29:80]**

[1] C.R.S.A. § 29-20-104.

[2] *See* Board of County Com'rs, La Plata County v. Bowen/Edwards Associates, Inc., 830 P.2d 1045, 1058 (Colo. 1992).

[3] The declared purposes of the Oil and Gas Conservation Act are as follows: to promote the development, production, and utilization of the natural resources of oil and gas in the state; to protect public and private interests against the evils of waste; to safeguard and enforce the coequal and correlative rights of owners and producers in a common source or pool of oil and gas so that each may obtain a just and reasonable share of production therefrom; and to permit each oil and gas pool to produce up to its maximum efficient rate of production subject to the prohibition of waste and subject further to the enforcement of the coequal and correlative rights of common-source owners and producers to a just and equitable share of profits.

[4] "The purpose of the county regulations is to 'facilitate the development of oil and gas resources within the unincorporated area of La Plata County while mitigating potential land-use conflicts between such development and existing, as well as planned, land uses.' "

[5] The Court stated that it was unable to make a determination given the record before them.

regulations.[6] In Colorado, each local government has the authority to reasonably plan for and regulate the use of land by regulating many functions, including the "surface impacts of oil and gas operations" to best protect and serve public health, safety, welfare, and the environment.[7] This statute is not meant to limit, alter, or expand any power already granted to local governments. In *City of Longmont*, Longmont added an article to its home-rule charter, prohibiting fracking.[8] and the Colorado Oil and Gas Association sued Longmont to invalidate it. Granting summary judgment for the Oil and Gas Association, the trial court found the amendment preempted by the Oil and Gas Conservation Act.[9] The Colorado Supreme Court of Colorado agreed and further found fracking to be exceptionally important in the production of oil and gas.[10] Because hydraulic fracturing is a commonly used technology in oil and gas extraction, banning it could lead to an extreme decrease in extraction efficiency across Colorado, making this local amendment a matter of statewide concern.[11] The Court did not want this one local charter amendment to create a "ripple effect" and influence other municipalities to ban the extraction method, because that would cause a drift away from statewide uniformity.[12]

Like Colorado, many states consider whether the municipal ordinance and state statute work together in supporting similar goals, or are in conflict. For example, in Pennsylvania, oil and gas operators, Huntley and Huntley (Huntley),[13] sought to operate a natural gas well on residential properties in "the Borough."[14] Huntley entered into commercial lease agreements with the affected property owners and obtained the required permit from the state. Later, however, the Borough Council and the municipal zoning officer directed Huntley to cease operations on the well because it violated the Borough's zoning ordinance.[15] In accordance with the local ordinance, Huntley then submitted a conditional use application. The Council conducted a standard hearing to consider the application, then it denied the application. The Council found, in part, that state law did not preempt its restriction.[16] In *Huntley & Huntley*, however, the Supreme Court of Pennsylvania cited *United Tavern Owners,* which said "[e]ven where the state has granted power to act in a particular field, . . . such powers do not exist if the Commonwealth preempts the field."[17] The Court looked to the purposes of both the local ordinance and Pennsylvania's Oil and Gas Statute. The main purpose of the Borough's ordinance was to protect and preserve the character of residential areas, whereas the state legislature's main purposes in the Oil and Gas Act were public health and

[6]*See* City of Longmont v. Colorado Oil and Gas Association, 2016 CO 29, 369 P.3d 573, 586, 82 Env't. Rep. Cas. (BNA) 1509, 182 O.G.R. 210 (Colo. 2016) (holding that a city's fracking ban [to be preempted because it] . . . materially impeded the effectuation of the state's interest).

[7]Colorado Rev. Stat. Ann. § 29-20-104.

[8]Hydraulic fracturing (or fracking) is a process used to stimulate oil and gas production from an existing well.

[9]*See* Colo. Rev. Stat. Ann. § 34-60-101.

[10]*Longmont*, 369 P.3d at 580.

[11]*Longmont*, 369 P.3d at 580.

[12]*Longmont*, 369 P.3d at 581.

[13]Huntley & Huntley, Inc. v. Borough Council of Borough of Oakmont, 600 Pa. 207, 225, 964 A.2d 855, 168 O.G.R. 524 (2009). Huntley is an engineering company involved in the oil and gas industry in Pennsylvania.

[14]"The Borough" is the Borough of Oakmont, Allegheny County, Pennsylvania.

[15]The ordinance considered drilling for natural gas to be an extraction of minerals, which was only permitted in an R-1 district on a conditional basis.

[16]*Huntley*, 600 Pa. at 213.

[17]*See* United Tavern Owners of Philadelphia v. School Dist. of Philadelphia, 441 Pa. 274, 279, 272 A.2d 868 (1971).

safety.[18] So, the purposes were different, and not in support of similar goals. Although the ordinance likely also responded to some public health concerns, its main purposes did not align with the main purposes of the Act. Thus, the Court held that the statute preempted the local ordinance.[19]

Although local governments may enact local regulations enacted pursuant to state law, a local government cannot enact a regulatory scheme that presents an obstacle to the purposes behind state law.[20] In *Range Res.—Appalachia v. Salem Twp. (Range Resources)*, Salem Township, Pennsylvania, enacted an ordinance regulating surface and land development associated with oil and gas drilling.[21] In response, several oil and gas producers sued, arguing that Pennsylvania's Oil and Gas Act preempted this ordinance.[22] The trial court held that Pennsylvania's Oil and Gas Act had addressed the alleged purposes behind the ordinance and that once the state has acted pursuant to such purposes, municipalities are prohibited from exercising police power to accomplish the same.[23] Both the Commonwealth and Supreme Courts of Pennsylvania affirmed stating that "[t]he comprehensive and restrictive nature of [the ordinance's] regulatory scheme represents an obstacle to the legislative purposes underlying the Act, thus implicating principles of conflict preemption.[24]

## § 29:81 Dillon's rule

Some states apply Dillon's Rule to the scope of local regulatory authority. Dillon's Rule provides that non-home rule governmental units possess only those powers specifically granted to them by the state's constitution or by the state legislature.[1] Therefore, municipal government units subject to Dillon's Rule, may regulate in a field occupied by state legislation, sometimes oil and gas activities, only when the state's constitution or state legislation specifically granted that authority.[2] In Illinois, for example, a place is a non-home-rule unit if it has fewer than 25,000 inhabitants and has not elected by referendum to become a home rule unit of government.[3]

In *Village of Sugar Grove v. Rich*, a resident received citations for violating several ordinances within the village of Sugar Grove, Illinois. Following his conviction on several of the violations, he appealed others arguing, for example, that the noise ordinances were preempted by state law.[4] Although the court found that Sugar Grove's population was not sufficient to exercise home rule power, the court held that the Illinois Environmental Protection Act did not reserve noise regulation to

[18] *Huntley*, 600 Pa. at 223–25.

[19] *Huntley*, 600 Pa. at 225.

[20] Range Resources Appalachia, LLC v. Salem Tp., 600 Pa. 231, 964 A.2d 869, 168 O.G.R. 507 (2009) (citing *Huntley*, but clarifying that local regulations enacted pursuant to state laws are permitted).

[21] Range Resources Appalachia, LLC v. Salem Tp., 600 Pa. 231, 964 A.2d 869, 168 O.G.R. 507 (2009).

[22] Appellees also argued that other federal and state enactments preempted the ordinance, but those are not at issue here.

[23] *Range Res. Appalachia*, at 234.

[24] The Supreme Court frequently cites *Huntley* for its similar facts and analysis.

**[Section 29:81]**

[1] *See* Owens v. City Council of City of Norfolk, 78 Va. Cir. 436, 440 (2009) (citing City of Richmond v. Board of Sup'rs of Henrico County, 199 Va. 679, 101 S.E.2d 641, 644–45 (1958)).

[2] Owens v. City Council of City of Norfolk, 78 Va. Cir. 436, 440 (2009) (citing City of Richmond v. Board of Sup'rs of Henrico County, 199 Va. 679, 101 S.E.2d 641, 644–45 (1958)).

[3] Village of Sugar Grove v. Rich, 347 Ill. App. 3d 689, 283 Ill. Dec. 559, 808 N.E.2d 525 (2d Dist. 2004).

[4] *Rich* cites the Environmental Protection Act.

only the state. Further, the court held that the purpose of the ordinance harmonizes well with the statute. Therefore, because they could coexist peacefully, the statute did not preempt the ordinance.[5]

In the realm of oil and gas regulation, an Illinois court has held that a non-home-rule unit of government may prohibit the drilling or operation of an oil or gas well within its municipal limits.[6] In *Tri Power Resources v. City of Carlyle*, a developer entered into an oil and gas lease and obtained the required drilling permit from Illinois's Department of Natural Resources.[7] Three months later, the City of Carlyle annexed the land, deeming it a residential district under its zoning ordinance.[8] Because of this new zoning classification, there could be no drilling or operating oil and gas wells on the parcel. The developer sued Carlisle, seeking a declaration that the new zoning ordinance was preempted by state law.[9] The court, citing *Rich*, first determined that Carlyle is a non-home rule municipality, so Dillon's Rule governs. The court then looked at the language of Illinois's Oil and Gas Act. Under § 13 of the state law, corporate authorities of each municipality have the authority to issue permits for the oil and gas mining to protect property. Here, Carlyle acted within the parameters of its powers under the state law; thus, the state law did not preempt Carlisle's ordinance.[10]

## § 29:82 State constitution and statute-based home rule

New York has witnessed more local governments move to ban or control oil and gas-related activities than any other state.[1] These local efforts have been effective for two primary reasons. First, New York's constitution contains a home rule provision—similar to other states– granting local government the power to adopt and amend local laws not inconsistent with the state constitution or any general law of the state.[2] Second, New York has enacted legislation to further buttress home rule powers of local jurisdictions. In support of the constitutional provision, the New York legislature has adopted the Municipal Home Rule Law, empowering local governments to pass laws for the "protection and enhancements of their physical and visual environment" and the health and well-being of persons and property in a local jurisdiction.[3] Additionally, the legislature enacted the Town Law, which authorizes towns to enact zoning laws to effectuate local police powers, and the

[5] *Village of Sugar Grove*, 808 N.E.2d at 531.

[6] Tri-Power Resources, Inc. v. City of Carlyle, 359 Ill. Dec. 781, 967 N.E.2d 811, 817, 84 A.L.R.6th 663 (App. Ct. 5th Dist. 2012) (holding that "a non-home-rule unit of government may prohibit the drilling or operation of an oil or gas well within its municipal limits").

[7] Tri-Power Resources, Inc. v. City of Carlyle, 359 Ill. Dec. 781, 967 N.E.2d 811, 812, 817, 84 A.L.R.6th 663 (App. Ct. 5th Dist. 2012).

[8] Tri-Power Resources, Inc. v. City of Carlyle, 359 Ill. Dec. 781, 967 N.E.2d 811, 817, 84 A.L.R.6th 663 (App. Ct. 5th Dist. 2012).

[9] Tri-Power Resources, Inc. v. City of Carlyle, 359 Ill. Dec. 781, 967 N.E.2d 811, 817, 84 A.L.R.6th 663 (App. Ct. 5th Dist. 2012).

[10] Tri-Power Resources, Inc. v. City of Carlyle, 359 Ill. Dec. 781, 967 N.E.2d 811, 816–17, 84 A.L.R. 6th 663 (App. Ct. 5th Dist. 2012).

**[Section 29:82]**

[1] *See* FRACTRACKER ALLIANCE, https://www.fractracker.org/map/us/new-york/moratoria/ (last visited June 29, 2021); *see also* OFFICE OF THE GOVERNOR, NEW YORK STATE, *Governor Cuomo Announces Legislation to Make the Fracking Ban Permanent Included in FY 2021 Executive Budget* (Jan. 22, 2020), https://www.governor.ny.gov/news/governor-cuomo-announces-legislation-make-fracking-ban-permanent-included-fy-2021-executive.

[2] *See* N.Y. Const. art. IX, § 2(c)(ii).

[3] Robertson, *When States' Legislation and Constitutions Collide with Angry Locals: Shale Oil and Gas Development and its Many Masters*, 41 WM. & MARY ENVTL. L. & POL'Y REV. 55, 122–23

Statute of Local Governments—granting towns the power to shape zoning regulations.[4]

In *City of Dryden*, Dryden, New York amended its Zoning Ordinance to prohibit all activities related to exploration for, production of, and storage of natural gas and petroleum.[5] Anschutz Exploration, an oil and gas developer, owned gas leases throughout Dryden and had invested millions of dollars into those operations. The developer sued Dryden, arguing that the charter amendment was preempted by New York's Oil, Gas and Solution Mining Law (OGSML).[6] The Supreme Court of Tompkins County, New York, citing *Matter of Frew Run*, analyzed preemption under New York's Mined Land Reclamation Law (MLRL). Similar to the OGSML, the MLRL includes a supersedure clause. The court reasoned that neither state law explicitly preempted local zoning authority. Further, the OGSML's purpose was to regulate all production and development of oil and gas, not to maximize the development of the oil and gas resources in New York. Therefore, the Court held that this purpose does not abridge local power to regulate delegated powers, meaning there was no preemption.

Similarly, Texas employs a home rule system based both in statute and its constitution[7] stating that, "absent an express limitation, if the general law and local regulation can coexist peacefully without stepping on each other's toes, both will be given effect, or the latter will be invalid only to the extent of any inconsistency."[8] Texas applies an analysis that is similar to that of *Bowen/Edwards*.[9] In *City of Laredo v. Laredo Merchs. Ass'n*, Laredo enacted an ordinance banning the use of certain plastic checkout bags by commercial establishments. Its declared purpose was to reduce litter. The Laredo Merchants Association sued the City of Laredo, arguing that the Texas Health and Safety Code preempted the ordinance.[10] The trial court held that the ordinance and the state law could exist without encroaching on one another. The Supreme Court of Texas agreed that general laws and local regulations could coexist peacefully; however, the Court also stated that the Texas legislature clearly intended to preempt municipalities from exercising its police powers in this particular area of governance. On this point, it said "[the statute] describes a state interest in 'controlling the management of solid waste' that is plenary."[11] Finally, the Court held that the home-rule provision did not authorize Laredo's regulatory method. Therefore, the state law preempted the municipal

(2016).

[4]Robertson, *When States' Legislation and Constitutions Collide with Angry Locals: Shale Oil and Gas Development and its Many Masters*, 41 WM. & MARY ENVTL. L. & POL'Y REV. 55, 122–23 (2016).

[5]Anschutz Exploration Corp. v. Town of Dryden, 35 Misc. 3d 450, 469, 940 N.Y.S.2d 458, 181 O.G.R. 1127 (Sup 2012), judgment aff'd, 108 A.D.3d 25, 964 N.Y.S.2d 714, 181 O.G.R. 1143 (3d Dep't 2013), order aff'd, 23 N.Y.3d 728, 992 N.Y.S.2d 710, 16 N.E.3d 1188, 181 O.G.R. 1166 (2014). The underlying purpose was to prohibit fracking. Dryden is located in the Marcellus shale region, and faced a proposed use of high-volume fracking to obtain natural gas from Marcellus black shale formation. *See* Anschutz Exploration Corp. v. Town of Dryden, 35 Misc. 3d 450, 452, 469, 940 N.Y.S.2d 458, 181 O.G.R. 1127 (Sup 2012), judgment aff'd, 108 A.D.3d 25, 964 N.Y.S.2d 714, 181 O.G.R. 1143 (3d Dep't 2013), order aff'd, 23 N.Y.3d 728, 992 N.Y.S.2d 710, 16 N.E.3d 1188, 181 O.G.R. 1166 (2014).

[6]OGSML has a supersedure clause that stated: "The provisions of this article shall supersede all local laws or ordinances relating to the regulation of the oil, gas, and solution mining industries . . . ."

[7]*See* Tex. Local Gov't. § 9.001, *available at* https://statutes.capitol.texas.gov/Docs/LG/htm/LG.9.htm.

[8]City of Laredo v. Laredo Merchants Association, 550 S.W.3d 586 (Tex. 2018).

[9]Board of County Com'rs, La Plata County v. Bowen/Edwards Associates, Inc., 830 P.2d 1045 (Colo. 1992).

[10]*See* § 342.001 of this Code.

[11]*City of Laredo*, 550 S.W.3d at 594.

ordinance.

## § 29:83 Explicit statutory preemption of oil and gas activities

Some state statutes explicitly prohibit municipal regulation of oil and gas activities. For example, like many states, North Carolina's legislature seeks to maintain a uniform system of oil and gas regulation (among other things) and prohibits local governments from restricting or conditioning oil and gas exploration, development, and production, including the use of drilling and hydraulic fracturing to achieve those purposes.[1] Similarly, in Ohio, the legislature has adopted a uniform system of comprehensive statewide legislation that has been recognized as a general law by the Ohio Supreme Court for purposes of oil and gas regulation.[2] Pursuant to this general law, local governments may not interfere with the state regulation of any oil and gas activities covered by the legislation and any local ordinance which conflicts with the general law is preempted.[3] Louisiana has also has adopted express state preemption statutes concerning the grant of oil and gas well permits.[4] Pursuant to Louisiana Revised Statute 30:28, no person may drill an oil or gas well without first obtaining a drilling permit from the Office of Conservation, and no local ordinance or zoning authority may interfere with a permit so obtained.[5]

Other states' legislatures specifically allow local regulation of oil and gas activities. For example, Oklahoma allows for municipalities, counties, or other political subdivisions to enact reasonable ordinances concerning oil and gas operations, so long as those ordinances are not inconsistent with any state statutes.[6] The statute further explains that political subdivisions may not explicitly or effectively prohibit oil and gas operations.[7] Pennsylvania allows municipalities permitting authority over oil and gas activities.[8] As discussed above, New York municipalities may utilize zoning authority to regulate oil and gas activities.[9]

## § 29:84 Zoning

As discussed, municipal governments still seek influence over the oil and gas-related activities within their jurisdictions. Some have turned to ordinance-based zoning approaches; that is, using their traditional zoning authority to regulate oil

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**[Section 29:83]**

[1] *See* N.C. Gen. Stat. § 113-415.1.

[2] State ex rel. Morrison v. Beck Energy Corp., 143 Ohio St. 3d 271, 275-77, 2015-Ohio-485, 37 N.E.3d 128 (2015).

[3] State ex rel. Morrison v. Beck Energy Corp., 143 Ohio St. 3d 271, 275-77, 2015-Ohio-485, 37 N.E.3d 128 (2015); *see also* Ohio Rev. Code Ann. § 1509.02 (West 2017). *See also* McCready, *Like it or Not, You're Fracked: Why State Preemption of Municipal Bans are Unjustified in the Fracking Context*, 62 Drexel L. Rev. Online 9, 75 (2016), https://ansp.org/~/media/Files/law/law%20review/v9-1/McCready.ashx.

[4] Hall, *When Do State Oil and Gas or Mining Statutes Preempt Local Regulations?*, 27 NAT. RES. & ENV'T 3 (2013).

[5] Hall, *When Do State Oil and Gas or Mining Statutes Preempt Local Regulations?*, 27 NAT. RES. & ENV'T 3, 14 (2013).

[6] *See* 52 Okla. Stat. Ann. § 137.1.

[7] "Operations" includes exploration, drilling, fracking, completion, maintenance, plugging, and abandonment to name a few.

[8] *See* 53 Pa. Con. Stat. § 10101 (1968).

[9] *See* Anschutz Exploration Corp. v. Town of Dryden, 35 Misc. 3d 450, 469, 940 N.Y.S.2d 458, 181 O.G.R. 1127 (Sup 2012), judgment aff'd, 108 A.D.3d 25, 964 N.Y.S.2d 714, 181 O.G.R. 1143 (3d Dep't 2013), order aff'd, 23 N.Y.3d 728, 992 N.Y.S.2d 710, 16 N.E.3d 1188, 181 O.G.R. 1166 (2014).

and gas or prohibit related activities in specific land use zones.[1] For example, in New York State, the Town of Dryden enacted a zoning ordinance that would control certain oil and gas-related activities. In *Norse Energy Corp. USA v. Town of Dryden*,[2] the court found Dryden's use of its zoning authority to be a permissible use of the home-rule power. In *Norse*, an oil and gas developer sued Dryden, arguing that the OGSML preempted Dryden's ordinance.[3] The court followed the *Anschutz* analysis due to factual similarities and found the ordinance not preempted by the state statute. Similarly, in *Cooperstown Holstein Corp. v. Town of Middlefield*,[4] the Town of Middlefield, New York banned oil, gas, and solution mining and drilling within the town. A holder of oil and gas leases in the town sued Middlefield arguing, again, that New York's OGSML preempted Middlefield's ordinance. Relying on *Norse,*[5] the court disagreed and upheld the ordinance.[6] In Pennsylvania, too, municipalities have used their zoning authority as allowed under that state's constitution.[7]

## § 29:85 Related obstacles to municipal authority

In some states, corporate influence has an outsized impact on state legislatures and pushes to increase state preemption of local control in the purported interest of a state-controlled unified system of regulation. For example, Florida SB 712—an amendment to Florida's Environmental Protection Act—passed in 2020 and was billed largely as a landmark environmental bill for the state envisioned as restoring water treatment standards and environmental protections for water systems in the state.[1] However, buried in the large regulatory bill was a late-stage amendment establishing state preemption of local rights based ordinances and charter amendments, such as the local laws discussed throughout this writing.[2] Following SB 712's adoption, environmentalists in the state filed numerous federal lawsuits challenging this state level preemption of local protection efforts.[3]

In Ohio, the state legislature included an effort to enact a statewide preemption of local environmental protection in an omnibus budget bill in 2019.[4] Emails obtained in a FOIA request show that, weeks before a vote on the budget bill, Ohio Chamber of Commerce Director of Energy and Environmental Policy, Zack Frymier,

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**[Section 29:84]**

[1]*See generally* Giller, *Implied Preemption and Its Effect on Local Hydrofracking Bans in New York*, 21 J.L. & POL'Y 631, 647 (2013).

[2]Norse Energy Corp. USA v. Town of Dryden, 108 A.D.3d 25, 964 N.Y.S.2d 714, 181 O.G.R. 1143 (3d Dep't 2013), order aff'd, 23 N.Y.3d 728, 992 N.Y.S.2d 710, 16 N.E.3d 1188, 181 O.G.R. 1166 (2014) (holding the zoning approach to be a permissible use of the home-rule power).

[3]This is the same ordinance and statute at issue in *Anschutz*.

[4]Cooperstown Holstein Corp. v. Town of Middlefield, 106 A.D.3d 1170, 1171, 964 N.Y.S.2d 431, 181 O.G.R. 1164 (3d Dep't 2013), order aff'd, 23 N.Y.3d 728, 992 N.Y.S.2d 710, 16 N.E.3d 1188, 181 O.G.R. 1166 (2014) (affirming *Norse*).

[5]Since the Court relied on *Norse*, it also must have relied on *Anschutz*.

[6]*Cooperstown*, 106 A.D.3d at 1171.

[7]Huntley & Huntley, Inc. v. Borough Council of Borough of Oakmont, 600 Pa. 207, 225, 964 A.2d 855, 168 O.G.R. 524 (2009) (applying the Colorado Home Rule Approach and the zoning approach).

**[Section 29:85]**

[1]Renzo Downey, *Gov. DeSantis signs Clean Waterways Act*, FLORIDA POLITICS (June 30, 2020), *Available at* https://floridapolitics.com/archives/345170-gov-desantis-signs-clean-waterways-act.

[2]Scott Powers, *Environmentalists challenge 'rights of nature' preemption in SB 712*, FLORIDA POLITICS (July 2, 2020), *available at* https://floridapolitics.com/archives/345753-environmentalists-challenge-rights-of-nature-preemption-in-sb-712.

[3]*See, e.g.*, Speak Up Wekiva, Inc. v. Desantis, No. 6:20-CV-01173 (M.D. Fl. July 29, 2020).

[4]Ohio Rev. Code Ann. § 2305.011 (West 2019).

requested a meeting with Chairman Hoops of the Ohio House Finance Subcommittee on Agriculture, Development, and Natural Resources to discuss inclusion of preemption language in the final bill.[5] Some activists have viewed this as a direct response to the Lake Erie Bill of Rights and related local ordinances throughout Ohio which seek to establish local control over natural resources.[6]

Additionally, Ohio recently faced a widely publicized legislative scandal—the Householder scandal—in which the Speaker of the Ohio House of Delegates, Larry Householder, and other state house members accepted bribes from energy corporations and lobbyists to pass favorable energy legislation.[7] Although the FBI has arrested and is currently investigating Householder,[8] he remains in the Ohio legislature.[9]

## VII. ENVIRONMENTAL LAWS AND OIL AND GAS

### A. NATIONAL ENVIRONMENTAL POLICY ACT

### § 29:86 Introduction

The National Environmental Policy Act (NEPA) applies to projects and other activities undertaken by private oil and gas companies in the United States in much the same way the law applies to the development of other private infrastructure, agriculture, and similar activity that qualifies as a "major federal action."[1] Common examples of industry activity subject to NEPA include exploration and production of oil and gas resources on Federal lands and the Outer Continental Shelf, construction of interstate natural gas pipelines and oil and natural gas pipelines that cross Federal lands or international borders, and construction and operation of petroleum refineries and liquefied natural gas (LNG)[2] terminals. Accordingly, industry operations are subject to NEPA review decisions and consultations made by the Bureau of Land Management (BLM), the Bureau of Ocean Energy Management, the Department of Energy (DOE), the Environmental Protection Agency, the Federal Energy Regulatory Commission (FERC), the Department of State (DOS), the U.S. Fish and Wildlife Service, the National Marine Fisheries Service, the U.S. Army Corps of Engineers, and the U.S. Forest Service, among others.

Given the size and complexity of many industry activities, discrete projects may require multiple permits or authorizations from several federal agencies that would be subject to NEPA review, in addition to any required authorizations from state

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[5] H. Claire Brown, *How Ohio's Chamber of Commerce Killed an Anti-Pollution Bill of Rights*, The Intercept (Aug. 29, 2019, 8:00 AM), https://theintercept.com/2019/08/29/lake-erie-bill-of-rights-ohio/.

[6] H. Claire Brown, *How Ohio's Chamber of Commerce Killed an Anti-Pollution Bill of Rights*, The Intercept (Aug. 29, 2019, 8:00 AM), https://theintercept.com/2019/08/29/lake-erie-bill-of-rights-ohio/.

[7] Andrew J. Tobias, *Nuclear Bailout Bill Shows How Big Money Can Be Put to Work in the Ohio Statehouse*, Cleveland.com (May 23, 2019), https://www.cleveland.com/news/g66l-2019/05/ce7f1b02ee6954/nuclear-bailout-bill-shows-how-big-money-can-be-put-to-work-in-the-ohio-statehouse.html.

[8] Anna Staver, *Former House Speaker Larry Householder Won't Be Removed for Now, Despite GOP Assurances*, Columbus Dispatch (Jan. 4, 2021), https://www.dispatch.com/story/news/politics/elections/2021/01/04/larry-householder-will-remain-in-house-as-ohio-general-assembly-sets-priorities-legislative/4072168001/.

[9] Anna Staver, *Former House Speaker Larry Householder Won't Be Removed for Now, Despite GOP Assurances*, Columbus Dispatch (Jan. 4, 2021), https://www.dispatch.com/story/news/politics/elections/2021/01/04/larry-householder-will-remain-in-house-as-ohio-general-assembly-sets-priorities-legislative/4072168001/.

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[1] 42 U.S.C. § 4332(2)(C); 40 C.F.R. § 1508.1(q) (2021); §§ 10:13 to 10:18 of this treatise.

[2] LNG is natural gas that has been cooled to -260? Fahrenheit, after which large-scale export facilities can load it into specialized tank vessels for overseas transport.

and local agencies.[3] For example, the construction and operation of an LNG export facility may require, at a minimum, authorization from FERC to site and construct the facility,[4] as well as authorization from DOE to export the LNG commodity,[5] both of which may be subject to separate NEPA reviews. Depending on the type of project and whether it can rely on existing permitted infrastructure, such an export facility may also require NEPA-triggering permits to construct and operate interstate natural gas pipelines feeding the facility, permits under the Clean Water Act to dredge and fill waterways, and potentially many others.

The NEPA process to permit large infrastructure projects, including oil and gas projects, has had the potential to be complex and lengthy since the law's inception. In recent years, the process has grown even more complicated, owing to, among other factors, evolving regulations and guidance documents implementing NEPA issued by federal agencies that oversee oil and gas permitting, increased opposition to oil and gas projects nationwide, and increased litigation or the threat of litigation regarding the scope and adequacy of NEPA review.[6] As a result, NEPA can present significant procedural hurdles to private companies in the form of lengthy permitting times at agencies, additional mitigation measures or other conditions placed on projects by agencies conducting NEPA reviews, and, in extreme cases, vacatur of permits, leases, or other authorizations by courts.

Part of the problem may be that NEPA, as currently drafted, is ill-equipped to properly address the nature of modern oil and gas projects in the 21st century. The text of the NEPA statute has not been amended since 1970, and its application to increasingly complex projects deploying new technologies and generating potentially adverse effects not foreseen by Congress has arguably grown more difficult for implementing agencies, the regulated community, affected stakeholders, and courts. In particular, whether the scope of NEPA reviews should include assessments of greenhouse gas emissions related to oil and gas projects has been a major source of uncertainty for over a decade.

## § 29:87 Role of White House Council on Environmental Quality in Oil and Gas Projects

As a formal matter, the Council on Environmental Quality (CEQ) established by NEPA has no specific role with respect to oil and gas projects. CEQ's original 1978 regulations and its recent 2020 amendments do not mention oil and gas, and the details of how to conduct NEPA reviews of proposed industry activity have been left to individual permitting agencies such as BLM and FERC. However, many of CEQ's guidance documents hold significance for certain oil and gas activities. For example, CEQ's 2014 "Effective Use of Programmatic NEPA Reviews" was intended to "address the general environmental issues relating to broad decisions, such as those establishing policies, plans, programs, or suite of projects . . . . [P]rogrammatic NEPA review provides the basis for decisions to approve such broad or high-level decisions such as identifying geographically bounded areas within which future proposed activities can be taken or identifying broad mitigation and conservation

[3]Several states have also enacted NEPA-like statutes applicable to industry activity, such as exploration and production, on state and private lands or that requires state authorization. *See, e.g.,* Cal. Pub. Res. Code §§ 21000, et seq. (California Environmental Quality Act); N.Y. Envtl. Conserv. Law §§ 8 et seq. (New York State Environmental Quality Review Act); § 7:12 of this treatise.

[4]15 U.S.C. § 717b(e).

[5]15 U.S.C. § 717b(a) to (c).

[6]According to CEQ, from 2001 through 2013 alone, 1,499 actions raising NEPA claims were filed in federal courts. CEQ, "NEPA LITIGATION SURVEYS: 2001-2013," *available at* https://ceq.doe.gov/docs/ceq-reports/nepa-litigation-surveys-2001-2013.pdf.

measures that can be applied to subsequent tiered reviews."[1] The guidance could apply to resource management planning decisions by BLM that govern the disposition of millions of acres of public lands under a single NEPA document, and increased use of high-level programmatic reviews in place of individual site-specific reviews could foreclose or limit disposition for oil and gas leases on individual parcels.[2]

In addition, CEQ has also grappled with how to address assessments of greenhouse gas emissions under NEPA in several guidance documents. A 2016 guidance document,[3] originally proposed in 2010,[4] provided information to agencies on quantification tools and how to weigh the impact of emissions when considering alternatives. This guidance was revoked in 2017.[5] In 2019, CEQ issued a new, less-detailed guidance document addressing some of the same issues,[6] but it was never finalized, and that too was revoked in early 2021.[7] In the absence of coherent guidance from CEQ, individual agencies have been left to consider questions related to greenhouse gas emission assessments in NEPA reviews on their own, with the potential for conflicting answers for combustive or emitting oil and gas projects.

## § 29:88 Process overview for oil and gas projects

The first question in determining whether NEPA review is required for a proposed industry action is whether the authorization required for the action under other applicable statutes is a "major federal action." While there is no specific test for oil and gas projects, as a practical matter, most new industry infrastructure development with a federal nexus (such as whether the activity occurs on Federal lands or waters or requires a permit or authorization from a Federal agency) will qualify. For example, if an oil and gas developer seeks to acquire a lease on onshore Federal lands to explore and drill for oil and gas deposits in the future, it typically must

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[1]CEQ, "EFFECTIVE USE OF PROGRAMMATIC NEPA REVIEWS," at 9–10 (Dec. 18, 2014), *available at* https://ceq.doe.gov/docs/ceq-regulations-and-guidance/Effective_Use_of_Programmatic_NEPA_Reviews_Final_Dec2014_searchable.pdf.

[2]The U.S. Supreme Court has favored limiting programmatic NEPA requirements even in the context of fossil fuel extraction on large swaths of Federal lands. For example, in Kleppe v. Sierra Club, 427 U.S. 390, 96 S. Ct. 2718, 49 L. Ed. 2d 576, 8 Env't. Rep. Cas. (BNA) 2169, 6 Envtl. L. Rep. 20532 (1976), the Court held that the Department of the Interior and other federal agencies "responsible for issuing coal leases, approving mining plans, and taking other actions to enable private companies and public to develop coal reserves on Federally owned or controlled land" were not required to issue a programmatic EIS for the entire Northern Great Plains region. Kleppe v. Sierra Club, 427 U.S. 390, 393, 96 S. Ct. 2718, 49 L. Ed. 2d 576, 8 Env't. Rep. Cas. (BNA) 2169, 6 Envtl. L. Rep. 20532 (1976). *Kleppe* reflects skepticism by the Court regarding programmatic reviews even for projects that share a number of factors in common, including location and type of activity. *See also* National Wildlife Federation v. Appalachian Regional Commission, 677 F.2d 883, 15 Env't. Rep. Cas. (BNA) 1945, 11 Envtl. L. Rep. 20386 (D.C. Cir. 1981) (promulgating factors for consideration of programmatic assessment).

[3]CEQ, "FINAL GUIDANCE FOR FEDERAL DEPARTMENTS AND AGENCIES ON CONSIDERATION OF GREENHOUSE GAS EMISSIONS AND THE EFFECTS OF CLIMATE CHANGE IN NATIONAL ENVIRONMENTAL POLICY ACT REVIEWS" (Aug. 1, 2016), *available at* https://ceq.doe.gov/docs/ceq-regulations-and-guidance/nepa_final_ghg_guidance.pdf.

[4]CEQ, "DRAFT NEPA GUIDANCE ON CONSIDERATION OF THE EFFECTS OF CLIMATE CHANGE AND GREENHOUSE GAS EMISSIONS" (Feb. 18, 2010), *available at* https://ceq.doe.gov/docs/ceq-regulations-and-guidance/20100218-nepa-consideration-effects-ghg-draft-guidance.pdf.

[5]"Withdrawal of Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews," 82 Fed. Reg. 16576 (Apr. 5, 2017).

[6]"Draft National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions," 84 Fed. Reg. 30097 (June 26, 2019).

[7]"National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions," 86 Fed. Reg. 10252 (Feb. 19, 2021).

purchase a lease from BLM. In order to dispose of leases, BLM must conduct a lease sale pursuant to the Mineral Leasing Act.[1] Lease sales are usually considered a "major federal action," and BLM will determine what level of NEPA review applies to a particular proposed sale. In most cases, potential lease sales to oil and gas companies have been considered under a BLM Resource Management Plan (RMP), a land use planning document also subject to NEPA review, usually in the form of an Environmental Impact Statement (EIS). The specific lease sale under consideration is generally limited to a portion of the acreage that is part of the larger RMP, and may consist of dozens or even hundreds of individual leases.

The next step is for an agency to determine if any applicable categorical exclusions apply to the action under review.[2] Categorical exclusions are set by individual agencies. In the example of leasing public lands for oil and gas development, it is unlikely that any categorical exclusions would apply to any of the major steps in the process—development of the RMP, conducting a lease sale, and ultimately issuing a permit to drill.[3] But BLM and other agencies have developed categorical exclusions applicable to industry activity for various reasons. DOE has promulgated categorical exclusions for LNG export authorizations,[4] on the basis that approval of the export of the LNG commodity alone would only entail environmental impacts in the form of marine transportation, which DOE has historically found to be not significant.[5] Other potential impacts related to LNG exports—such as those associated with the construction of new export facilities or combustion of LNG overseas—are outside of DOE's authority to prevent.[6]

If no categorical exclusion applies to the proposed action, an agency will next determine whether to conduct a shorter, more concise Environmental Assessment (EA), or to proceed to a longer detailed EIS. Like with categorical exclusions, many agencies herd particular types of actions into one of these groups under regulations and guidance.[7] As with any other action subject to NEPA review, the relevant agency determination at this stage is a Finding of No Significant Impact (FONSI). Actions for which a FONSI is issued conclude with an EA; otherwise, a complete EIS is conducted. For federal onshore oil and gas lease sales, BLM usually conducts an EA which can be "tiered" from the EIS accompanying the relevant RMP.

For larger and more complex oil and gas projects, many agencies may be involved in permitting different aspects of the project or consulting with permitting agencies on particular effects. When such projects require an EIS, practical and efficiency concerns may arise when determining which agency is in charge of preparing the EIS, as well as sequencing the timing of individual authorizations in a logical fashion to facilitate safe operations. In some cases, Congress has addressed this issue. For example, FERC has been statutorily designated as the "lead agency" for

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[1] 30 U.S.C. §§ 181 et seq.

[2] *See* § 10:10 of this treatise.

[3] BLM has created categorical exclusions for certain routine operations related to existing federal oil and gas wells. *See* BUREAU OF LAND MGMT., NEPA HANDBOOK App'x 4 (2008).

[4] 10 C.F.R. § 1021 (2021), Appx. B, § 5:7.

[5] "National Environmental Policy Act Implementing Procedures," 85 Fed. Reg. 78197, 78198 (Dec. 4, 2020).

[6] "National Environmental Policy Act Implementing Procedures," 85 Fed. Reg. 78197, 78198 (Dec. 4, 2020) (citing Department of Transp. v. Public Citizen, 541 U.S. 752, 768–770, 124 S. Ct. 2204, 159 L. Ed. 2d 60, 58 Env't. Rep. Cas. (BNA) 1545, 26 Int'l Trade Rep. (BNA) 1097, 34 Envtl. L. Rep. 20033 (2004); Sierra Club v. Federal Energy Regulatory Commission, 827 F.3d 59, 82 Env't. Rep. Cas. (BNA) 1860, 182 O.G.R. 1060 (D.C. Cir. 2016)).

[7] *See, e.g.,* BUREAU OF LAND MGMT., NEPA HANDBOOK 70 (2008) (listing BLM actions that normally require an EIS).

such in-depth and interlocking reviews under its jurisdiction. FERC prepares the EIS for jurisdictional projects like interstate natural gas pipelines, and coordinates with other state and federal permitting agencies to the extent practicable.[8] Historically, not every agency has been able to replicate this model due to statutory constraints, lack of interagency cooperation, or other reasons. To address these challenges (which are not exclusive to oil and gas projects), a 2017 Executive Order[9] requires agencies to conduct reviews and issue decisions for "major infrastructure projects"[10] under "One Federal Decision," with a goal of reducing average NEPA review and permitting timelines to two years from the date of publication of a notice of intent to prepare an EIS.

Last, final agency actions related to oil and gas projects are subject to judicial review. For decades, challenges to oil and gas projects have focused on the adequacy of NEPA review accompanying a permit or authorization. Plaintiffs may challenge an agency EA on grounds that the agency should not have issued a FONSI and instead conducted a full EIS. They may also challenge the substance of an EA or EIS on grounds that it failed to consider certain environmental impacts or alternatives to the authorized action, including the "no action" alternative. A major theme of NEPA litigation challenging oil and gas projects in recent years is whether and to what extent the agency considered the effects of greenhouse gas emissions related to the project.

### § 29:89 Major NEPA issues for oil and gas projects

Oil and gas projects can encounter any number of changes, setbacks, and other issues throughout the review process—including after judicial review, where NEPA defects may be remanded to agencies to correct or, in some instances, provide grounds for vacatur. Some of the biggest hurdles encountered by project sponsors in recent years include the proper scope of consideration of environmental "effects," the adequacy of alternatives considered, and agency mitigation measures imposed as a condition of authorization.

***Effects Generally.***[1] The U.S. Supreme Court has compared the relevant test for "effects" that must be considered in all NEPA reviews to the tort principle of "proximate cause."[2] Further, the action under review must be "the legally relevant cause" of such effects.[3] Thus, for example, an agency need not consider environmental effects of actions over which the agency has no control.[4] In its original 1978 NEPA regulations, which were not significantly amended until 2020, CEQ directed agen-

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[8] 15 U.S.C. § 717n(b).

[9] Exec. Order No. 13807, 82 Fed. Reg. 40463 (Aug. 24, 2017).

[10] "[A]n infrastructure project for which multiple authorizations by Federal agencies will be required to proceed with construction [where] the lead Federal agency has determined that it will prepare an [EIS], and the project sponsor has identified the reasonable availability of funds sufficient to complete the project." Exec. Order No. 13807, at § 3(e).

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[1] *See* §§ 10:17 to 10:18.

[2] Department of Transp. v. Public Citizen, 541 U.S. 752, 124 S. Ct. 2204, 159 L. Ed. 2d 60, 58 Env't. Rep. Cas. (BNA) 1545, 26 Int'l Trade Rep. (BNA) 1097, 34 Envtl. L. Rep. 20033 (2004) (citing W. Keeton, et al., Prosser and Keeton on Law of Torts 264, 274-75 (1983) for proximate cause standard). *See also* Metropolitan Edison Co. v. People Against Nuclear Energy, 460 U.S. 766, 774, 103 S. Ct. 1556, 75 L. Ed. 2d 534, 18 Env't. Rep. Cas. (BNA) 1985, 52 Pub. Util. Rep. 4th (PUR) 189, 13 Envtl. L. Rep. 20515 (1983); § 10:17.

[3] *Pub. Citizen*, 541 U.S. at 769.

[4] *Pub. Citizen*, 541 U.S. at 770 ("We hold that where an agency has no ability to prevent a certain effect due to its limited statutory authority over the relevant actions, the agency cannot be considered a legally relevant 'cause' of the effect."); National Ass'n of Home Builders v. Defenders of Wildlife, 551

cies to consider three major categories of environmental effects in their NEPA reviews: (1) direct effects; (2) indirect effects; and (3) cumulative effects. The terms "direct," "indirect," and "cumulative" do not appear in the text of the relevant provisions of NEPA, which refer only to "environmental impact[s]" and "adverse environmental effects" generally.[5] The 2020 CEQ regulations eliminate these three categories, and direct agencies to consider only those effects that are proximately caused by the action under review *and* for which the agency action is the legally relevant cause.[6]

Prior to the 2020 regulations entering into effect, a significant body of case law had considered the proper scope of assessing the direct, indirect, and cumulative effects of oil and gas projects, and many cases concerning projects reviewed under the 1978 regulations are still awaiting decision.[7] In addition, the durability of the 2020 regulations, particularly the changes to the definition of "effects," is in some doubt. The regulations were challenged in five separate cases pending in four federal courts, although only one court reached a decision dismissing a challenge for lack of justiciability.[8] The Biden Administration also announced that it would revisit the 2020 regulations[9] For these reasons, an examination of major NEPA cases involving oil and gas infrastructure under the 1978 regulations remains instructive.

***Direct vs. Indirect Effects:*** Some NEPA challenges to oil and gas infrastructure, such as oil and natural gas pipelines and LNG export facilities, have asserted that FERC must consider the "indirect" effects of permitting such a project in the form of emissions and other impacts of hydrocarbon extraction "upstream," and combustion "downstream," of the project under review—*i.e.*, the environmental effects of drilling wells feeding into the pipeline or export facility, as well as combustion of the product after transmission or export. As the Supreme Court has explained, the concept of causation is central to understanding an agency's obligation under NEPA to consider any effect, regardless of whether it is deemed direct or indirect. While an effect may bear some relationship to a Federal action, that is not the test for inclusion in a NEPA review. Effects must only be considered when there is a "reasonably

U.S. 644, 667, 127 S. Ct. 2518, 168 L. Ed. 2d 467, 64 Env't. Rep. Cas. (BNA) 1513 (2007) (same).

[5]42 U.S.C. § 4332(2)(C)(i) to (ii).

[6]Both elements of this test must be satisfied, and CEQ's 2020 definitional changes codify earlier case law on the issue. *See, e.g.,* City of Shoreacres v. Waterworth, 420 F.3d 440, 452–54, 60 Env't. Rep. Cas. (BNA) 2068, 35 Envtl. L. Rep. 20162 (5th Cir. 2005) (explaining that it does not reach the issue of whether the agency's action is the legally relevant cause of the effect because the relevant effect is not reasonably foreseeable); Border Power Plant Working Group v. Department of Energy, 260 F. Supp. 2d 997, 1016–17 (S.D. Cal. 2003) (finding that although it was reasonably foreseeable that two turbines would use transmission line at issue, only one turbine was the effect of DOE's approval of the transmission line and, therefore, DOE only was required to evaluate the environmental effects of that turbine in its NEPA analysis).

[7]For pending NEPA cases concerning the assessment of indirect effects of Federal oil and gas leases, *see, e.g.,* WildEarth Guardians v. Bernhardt, No. 20-56 (D.D.C.) (challenge to approval of 2,067 oil and gas leases across five western states); WildEarth Guardians v. Bernhardt, No. 19-505 (D.N.M.) (challenge to 210 federal oil and gas leases); Diné Citizens Against Ruining our Environment v. Bernhardt, No. 19-703 (D.N.M.) (alleged NEPA violations in approving 255 APDs authorizing hydraulic fracturing in the Mancos Shale formation in the San Juan Basin); Ctr. for Biological Diversity v. BLM, No. 19-2869 (D. Colo.) (challenge to Grand Junction Field Office's RMP and accompanying EIS under NEPA for allegedly failing to consider GHG emission-related impacts and alternatives); Rocky Mtn. Wild v. Bernhardt, No. 18-2468 (D. Colo.) and Rocky Mtn. Wild v. Bernhardt, No. 19-929 (D. Utah) (challenge to 121 federal oil and gas leases, severed into two cases); WildEarth Guardians v. Bernhardt, No. 16-1724 (D.D.C.) (challenge to 397 federal oil and gas leases for allegedly failing to consider emission-related impacts).

[8]Wild Virginia v. Council on Environmental Quality, 2021 WL 2521561 (W.D. Va. 2021).

[9]"Deadline for Agencies To Propose Updates to National Environmental Policy Act Procedures," 86 Fed. Reg. 34154, 34156 (June 29, 2021) ("CEQ will initiate further rulemaking to propose amendments to the 2020 Rule to revise the NEPA implementing regulations . . . .").

close causal relationship" that would satisfy a proximate cause analysis under tort law. While some commentators have argued for broader consideration of indirect effects under NEPA,[10] without some rational boundary, it would be possible to say that there are an infinite number of indirect effects from an action by an agency, making it impossible to consider all such effects and for the applicant to mitigate all such effects. A boundary must be set, and the Supreme Court has said that boundary is proximate cause.

For "upstream" effects, litigants challenging pipeline and export projects have argued that the development of oil and gas resources feeding into an infrastructure project must be considered in permitting decisions. Notably, this question formed the nucleus of legal arguments made in opposition to the permitting of the controversial Keystone XL pipeline carrying heavy crude oil from Alberta's oil sands into the United States. Opponents of the project sought a full assessment of development of higher-emitting oil sands projects in Canada as part of the NEPA review for the cross-border permit required from DOS to build the pipeline. DOS has permitted cross-border pipelines since long before the Keystone XL controversy emerged, and courts have upheld NEPA reviews for such pipelines that did not examine "upstream" effects, even of allegedly higher-emitting hydrocarbon sources. In *Sierra Club v. Clinton*,[11] a district court considered whether DOS was required to assess impacts associated with development of Canadian oil sands in its NEPA analysis accompanying a cross-border permit for the Alberta Clipper Pipeline.[12] Sierra Club filed suit alleging that DOS's NEPA analysis was insufficient because it did not take into account the environmental impacts of the Canadian oil sands development.[13] But, citing *Public Citizen*, the court found that DOS's actions were not the legally relevant cause of the environmental effects at issue, explaining that because the pipeline was not the only cross-border pipeline that would transport Canadian oil sands, this particular permit could not be the proximate cause of additional oil sands development.[14]

In the context of "downstream" effects, courts have arrived at different answers regarding when effects like combustion must be considered, depending on the facts of individual projects. For example, in *Sierra Club v. FERC*, the D.C. Circuit required FERC to consider the greenhouse gas emissions generated by a natural gas power plant fed by the Sabal Trail natural gas pipeline as part of the pipeline's EIS.[15] Even though the facility was beyond the footprint of the project and outside of FERC's jurisdiction, the court found the plant's emissions to be reasonably foreseeable and reasonably related to the project because it was the primary outlet for the pipeline and the reason for its construction. But under different facts, the D.C. Circuit has declined to require these assessments. In *Sierra Club v. FERC*, a case challenging the permitting of the Corpus Christi LNG export facility, the court held that FERC's "NEPA analysis did not have to address the indirect effects of the anticipated *export* of natural gas . . . because the Department of Energy, not the Commission, has sole authority to license the export of any natural gas."[16]

While the scope of "indirect" effects assessments in NEPA reviews of oil and gas

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[10] *See, e.g.,* Michael Burger and Jessica Wentz, "Downstream and Upstream Greenhouse Gas Emissions:

"The Proper Scope of NEPA Review," 41 Harv. Envtl. L. Rev. 109 (2017).

[11] Sierra Club v. Clinton, 746 F. Supp. 2d 1025, 177 O.G.R. 754 (D. Minn. 2010).

[12] Sierra Club v. Clinton, 746 F. Supp. 2d 1025, 1028–30, 177 O.G.R. 754 (D. Minn. 2010).

[13] Sierra Club v. Clinton, 746 F. Supp. 2d 1025, 177 O.G.R. 754 (D. Minn. 2010).

[14] Sierra Club v. Clinton, 746 F. Supp. 2d 1025 1045–46 and n.11, 177 O.G.R. 754 (D. Minn. 2010).

[15] Sierra Club v. Federal Energy Regulatory Commission, 867 F.3d 1357, 85 Env't. Rep. Cas. (BNA) 1035 (D.C. Cir. 2017).

[16] Sierra Club v. Federal Energy Regulatory Commission, 672 Fed. Appx. 38, 39 (D.C. Cir. 2016)

permits is far from settled, as a general matter, reviewing courts have tended to tie any requirements to assess particular indirect effects to the individual facts of a project, rather than send agencies on endless efforts to uncover any potential effects. This case-by-case inquiry, however, has been less easily applied in the context of "cumulative effects."

***Cumulative Effects.*** Identifying the proper scope for assessment of "cumulative effects" has been a particularly difficult issue for CEQ and courts to address in recent years. As CEQ itself has pointed out, determining what a cumulative effect is has led to "confusion," "been interpreted expansively[,]" and "result[ed] in excessive documentation about speculative effects[.]"[17] Generally speaking, cumulative effects in the context of oil and gas projects could include the effects of historical oil and gas well construction in a particular area and, potentially, the incremental effects of new permitting decisions on global climate change.

As one federal court has recently suggested, cumulative effects in the context of Federal oil and gas leasing might be so broad as to require assessments of the effects of all individual leasing decisions whenever BLM seeks to hold a lease sale.[18] In that court's view, BLM must "quantify the emissions from each leasing decision—past, present, or reasonably foreseeable—and compare those emissions to regional and national emissions, setting forth with reasonable specificity the cumulative effect of the leasing decision at issue."[19] This would be a herculean task for BLM to undertake prior to holding any individual lease sale. While several other courts have addressed this question in the oil and gas context, the agencies at issue had made at least some attempt to consider emissions-related cumulative effects, and were not directed to do more.[20] But no Court of Appeals has affirmed the expansive "past, present, or reasonably foreseeable" cumulative effects requirement in the oil and gas context, while some have explicitly rejected it in the context of LNG export facilities.[21] Even more than assessments of indirect effects, which can more easily be tied to specific factual considerations in the context of discrete projects, it is difficult to divine useful guideposts for what cumulative effects must be reviewed in the context of oil and gas projects–which is perhaps why CEQ no longer requires their consideration.

Attempts to require agencies to consider wider scopes of "indirect" and "cumulative" effects in the context of challenges to oil and gas infrastructure in recent years clearly reflect concerns over the effects of global climate change. Such concerns are rooted in active and worthy public policy conversations. However, as CEQ has said,

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(emphasis in original) (quoting Sierra Club v. Federal Energy Regulatory Commission, 827 F.3d 36, 47, 82 Env't. Rep. Cas. (BNA) 1849, 182 O.G.R. 1046 (D.C. Cir. 2016)). *See also* EarthReports, Inc. v. Federal Energy Regulatory Commission, 828 F.3d 949, 82 Env't. Rep. Cas. (BNA) 1970 (D.C. Cir. 2016).

[17] "Update to the Regulations Implementing the Procedural Provisions of the National Environmental Policy Act," 85 Fed. Reg. 1684, 1707 (Jan. 10, 2020).

[18] WildEarth Guardians v. Zinke, 368 F. Supp. 3d 41 (D.D.C. 2019).

[19] *Id.* at 77.

[20] WildEarth Guardians v. Bureau of Land Management, 8 F. Supp. 3d 17 (D.D.C. 2014) (Bureau of Land Management properly considered cumulative emissions impacts of oil and gas lease sale). *Cf.* Indigenous Environmental Network v. United States Department of State, 347 F. Supp. 3d 561 (D. Mont. 2018), order amended and supplemented, 369 F. Supp. 3d 1045 (D. Mont. 2018) and appeal dismissed and remanded, 2019 WL 2542756 (9th Cir. 2019) (agency conducted separate cumulative greenhouse gas emission impacts for two different pipeline authorizations, but was required to assess the cumulative impacts of both pipelines together).

[21] *See* EarthReports, Inc. v. Federal Energy Regulatory Commission, 828 F.3d 949, 82 Env't. Rep. Cas. (BNA) 1970 (D.C. Cir. 2016); Sierra Club v. Federal Energy Regulatory Commission, 827 F.3d 36, 82 Env't. Rep. Cas. (BNA) 1849, 182 O.G.R. 1046 (D.C. Cir. 2016).

"NEPA is a procedural statute"[22] that requires the identification and analysis of a proposed action's impact to environmental resources.[23] It does not mandate that certain outcomes be achieved or prohibit any impacts to environmental resources.[24] As further evidenced by CEQ's tumultuous history in issuing durable guidance regarding assessments of greenhouse gas emissions in NEPA reviews, the current statute may simply be ill-suited to meaningfully address such a titanic challenge.[25]

***Alternatives.*** Agency actions facilitating oil and gas project development are also frequently challenged on grounds that agencies did not consider a sufficient range of alternatives, including a "no action" alternative, or that the rejection of alternatives was not sufficiently justified. In *Citizens for a Healthy Community. v. BLM,* a challenge to oil and gas well development on Federal lands in Colorado, the court found that BLM's analysis of alternatives complied with NEPA where the agency considered alternatives proposed by plaintiffs regarding a phased development approach, and provided reasoned explanations for their rejection.[26] However, in *Wilderness Workshop v. BLM*, the same court found that BLM failed to adequately consider a "no action" alternative, even where BLM had considered scenarios in which development would have been minimal.[27]

***Mitigation.*** As the Supreme Court has noted, "one important ingredient of an EIS is the discussion of the steps that can be taken to mitigate adverse environment consequences."[28] The Court went on to explain that "[t]here is a fundamental distinction, however, between a requirement that mitigation be discussed in sufficient detail to ensure that environmental consequences have been fairly evaluated, on the one hand, and a substantive requirement that a complete mitigation plan be actually formulated and adopted on the other."[29] Citing *Methow Valley*, appellate courts have routinely confirmed that there is no substantive obligation to adopt mitigation measures identified in an EIS,[30] and this rule also applies in the oil and gas context.

In addition, extractive projects have also encountered mitigation measures imposed by agencies but over which the reviewing agency has no statutory authority or even particular expertise.[31] In response, CEQ's 2020 regulations impose new

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[22]"Update to the Regulations Implementing the Procedural Provisions of the National Environmental Policy Act," 85 Fed. Reg. 1684, 1686.

[23]*See* 42 U.S.C. § 4332(2)(C) (agency obligation under NEPA is only to prepare detailed statement on "adverse environmental effects which cannot be avoided"); Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc., 435 U.S. 519, 551, 98 S. Ct. 1197, 55 L. Ed. 2d 460, 11 Env't. Rep. Cas. (BNA) 1439, 8 Envtl. L. Rep. 20288 (1978).

[24]Robertson v. Methow Valley Citizens Council, 490 U.S. 332, 350, 109 S. Ct. 1835, 104 L. Ed. 2d 351, 29 Env't. Rep. Cas. (BNA) 1497, 19 Envtl. L. Rep. 20743 (1989).

[25]*Cf*. Michael Burger and Jessica Wentz, "Downstream and Upstream Greenhouse Gas Emissions: "The Proper Scope of NEPA Review," 41 HARV. ENVTL. L. REV. 109, 112–13 (2017) ("A significant part of the problem is that federal agencies have been slow to use [NEPA] to fully evaluate how decisions about the extraction and transportation of fossil fuels contribute to global climate change . . . . The net effect of this analytic gap is that neither the agencies nor the public have a clear understanding of how these decisions impact the nation's overall climate goals.").

[26]Citizens for a Healthy Community v. United States Bureau of Land Management, 377 F. Supp. 3d 1223, 1234-35 (D. Colo. 2019).

[27]Wilderness Workshop v. United States Bureau of Land Management, 342 F. Supp. 3d 1145, 1166 (D. Colo. 2018).

[28]*Robertson v. Methow Valley*, 490 U.S. at 351.

[29]*Robertson v. Methow Valley*, 490 U.S. at 352.

[30]*See, e.g.,* Westlands Water Dist. v. U.S. Dept. of Interior, 376 F.3d 853, 873, 58 Env't. Rep. Cas. (BNA) 2024, 34 Envtl. L. Rep. 20054 (9th Cir. 2004); Mississippi River Basin Alliance v. Westphal, 230 F.3d 170, 176–77, 31 Envtl. L. Rep. 20175 (5th Cir. 2000).

[31]*See, e.g.,* High Country Conservation Advocates v. United States Forest Service, 52 F. Supp. 3d

requirements for agency mitigation to include an express statutory basis.[32] Changes to the definition of "mitigation" make clear that mitigation must have an actual nexus to the proposed action and be limited to those actions that have an environmental effect while excluding those that do not.[33]

### § 29:90 Legislative proposals

In part as a response to the challenges posed by NEPA review of oil and gas projects, several proposals to amend NEPA or create parallel procedures were considered in the 116th Congress. One proposal would have required agencies to more directly consider issues related to environmental justice, including how greenhouse gas emissions and global climate change uniquely affect disadvantaged communities, both under NEPA and under a new "Community Impact Report."[1] Another would have streamlined and codified the "one federal decision" concept for projects requiring interlocking reviews by multiple agencies.[2] Amendments to NEPA are likely to be considered again in the 117th Congress.

## B. RESOURCE CONSERVATION AND RECOVERY ACT—THE REGULATION OF WASTE GENERATED AT OIL AND GAS EXPLORATION AND PRODUCTION FACILITIES

### § 29:91 Introduction

This section discusses the application of the Resource Conservation and Recovery Act (RCRA)[1] to wastes generated at oil and gas production facilities. Contrary to popular belief, RCRA applies. There is no exemption under RCRA that excludes *all* waste generated at oil and gas production facilities. While wastes generated from the exploration, development, or production of crude oil or natural gas (referred to herein as E&P Waste) are excluded from the definition of "hazardous wastes" under RCRA, those wastes are "solid wastes" and remain subject to RCRA and state law regulating the management of solid waste. Wastes that are not considered E&P Waste are also solid waste and may be regulated as hazardous waste if they contain listed hazardous waste or exhibit a hazardous waste characteristic. Those wastes must be properly managed and disposed.

To assist oil and gas production facilities, this chapter summarizes: (1) the statutory and regulatory exemptions for E&P Waste; (2) what wastes generated at oil and gas production facilities the U.S. Environmental Protection Agency (EPA) considers to be subject to regulation as a hazardous waste; and (3) how various states regulate E&P Waste. Generally, most of the waste generated at oil and gas production facilities should be E&P Waste and exempt from regulation as a hazardous waste under RCRA and delegated state programs.

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1174 (D. Colo. 2014) (U.S. Forest Service, part of the Department of Agriculture, could not rely on development of future coal mining mitigation technology to avoid disclosure of impacts in NEPA review).

[32] "Update to the Regulations Implementing the Procedural Provisions of the National Environmental Policy Act," 85 Fed. Reg. 1684, 1722.

[33] "Update to the Regulations Implementing the Procedural Provisions of the National Environmental Policy Act," 85 Fed. Reg. 1684, 1729.

**[Section 29:90]**

[1] H.R. 4447, 116th Cong. §§ 11001 et seq. (2020).

[2] H.R. 7130, 116th Cong. (2020).

**[Section 29:91]**

[1] The Resource Conservation and Recovery Act of 1976, 42 U.S.C.A. §§ 6901 to 6939g. For further discussion regarding RCRA *see* Law of Environmental Protection, Fall 2019 Edition, Environmental Law Institute, Chapter 14.

## § 29:92 The Resource Conservation and Recovery Act

RCRA, originally passed in 1976, establishes a framework governing the generation, treatment, storage, and disposal of both hazardous and non-hazardous solid wastes under Subtitles C and D respectively.[1] RCRA charged EPA with developing and promulgating criteria used to identify and list hazardous wastes to be regulated under RCRA Subtitle C.[2] RCRA authorizes EPA to delegate the primary responsibility of implementing the RCRA hazardous waste program to individual states in lieu of EPA.[3] Many states have also been authorized to implement additional parts of the RCRA program that EPA has since promulgated including corrective action, land disposal restrictions. and underground storage tanks. State RCRA programs must be at least as stringent as the federal requirements, but states can adopt more stringent requirements.

1. The Exploration and Production Waste Statutory Exemption

## § 29:93 History of the exemption

Following the passage of RCRA, EPA in 1978 published a proposed rule indicating categories of wastes the agency deemed "hazardous" and identifying the need for a separate regulatory scheme for (E&P Waste).[1] The proposed regulations recognized "some portion of certain very large volume exploration and production wastes will be hazardous"[2] under the statutory definition, which will subject the wastes to the authority of Subtitle C. Instead of subjecting large quantities of E&P Waste to Subtitle C, EPA instead suggested regulating the wastes as "special wastes" with less stringent requirements.[3] The proposed regulations highlighted many implications of regulating E&P Waste under Subtitle C, including the cost to the energy industry, the precedential nature of granting special treatment to certain industries, the possible interference with other applicable federal laws, and a fear of delegating too much authority to EPA.[4]

In response to the proposed rulemaking, Congress introduced legislation to determine whether and how these wastes should be regulated. Because it appeared that Congress would act, EPA temporarily excluded these wastes from the final hazardous waste regulations, stating that "this exclusion will be revised, if necessary, to conform to the legislation which is ultimately enacted."[5]

## § 29:94 The Bentsen Amendment

Through the Solid Waste Disposal Act Amendments of 1980, Senator Lloyd Bentsen of Texas sponsored an amendment exempting oil, gas, and geothermal E&P Wastes from EPA's hazardous waste regulatory authority.[1] Colloquially referred to as "Bentsen wastes," the amendment exempts "drilling fluids, produced waters, and

**[Section 29:92]**

[1] 42 U.S.C.A. §§ 6901 et seq.

[2] 42 U.S.C.A. § 6921(b).

[3] 42 U.S.C.A. § 6926.

**[Section 29:93]**

[1] 43 Fed. Reg. 58946 (Dec. 18, 1978).

[2] 43 Fed. Reg. 58991 (Dec. 18, 1978).

[3] 43 Fed. Reg. 58992 (Dec. 18, 1978).

[4] Congressional Record, June 4, 1979, pp. 13243–47.

[5] 45 Fed. Reg. 33084 (May 19, 1980).

**[Section 29:94]**

[1] Solid Waste Disposal Act Amendments of 1980, Pub. L. No. 96-482, 94 Stat. 2334 (Oct. 21, 1980).

other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy" from regulation as hazardous wastes under Subtitle C of RCRA until EPA studied and, after public hearing and opportunity for comment, determined regulation is warranted.[2] The amendment placed an additional limit on EPA authority: any proposed hazardous waste regulations governing Bentsen wastes must be approved by both Houses of Congress prior to taking effect.[3] It is important to note the Bentsen amendment only shields E&P Wastes from regulation as a hazardous waste under Subtitle C of RCRA. E&P Wastes are still considered solid wastes and remain subject to regulation under Subtitle D of RCRA and states are not restricted from imposing more stringent requirements on the management and disposal of E&P Waste.

The legislative history of the Bentsen amendment provides insight into which wastes do and do not fall within the scope of the amendment. While "drilling fluids" and "production wastes" are relatively straight forward terms, Congress included the term "other wastes associated" to cover "waste materials intrinsically derived from the primary field operations associated with exploration, development, or production of crude oil, natural gas, or geothermal energy."[4] This language differentiates "exploration, development, and production operations from transportation (from the point of custody transfer or of production separation and dehydration) and manufacturing operations."[5] In addition, Congress directed EPA to study the impact on the environment, human health, and the economy of regulating Bentsen wastes. RCRA tasks EPA to specifically consider:

(A) the sources and volume of discarded material generated per year from such wastes;
(B) present disposal practices;
(C) potential danger to human health and the environment from the surface runoff or leachate;
(D) documented cases which prove or have caused danger to human health and the environment from surface runoff or leachate;
(E) alternatives to current disposal methods;
(F) the cost of such alternatives; and
(G) the impact of those alternatives on the exploration for, and development and production of, crude oil and natural gas or geothermal energy.[6]

In 1987, EPA submitted a report to Congress summarizing its studies in compliance with the Bentsen amendment. EPA concluded that regulation of Bentsen wastes under Subtitle C was not warranted. According to EPA, regulation under Subtitle C would be "logistically difficult to enforce and could pose a substantial financial burden on the oil and gas industry."[7] EPA also concluded that the potential hazards posed by E&P wastes are relatively low and best addressed though existing federal and statute regulations.[8] The report included a list of wastes the agency considered exempt under the Bentsen amendment, as well as factors to help industry

[2] 42 U.S.C.A. § 6921(b)(2)(B).

[3] 42 U.S.C.A. § 6921(b)(2)(C).

[4] H.R. Conf. Rep. 96-1444.

[5] H.R. Conf. Rep. 96-1444.

[6] 42 U.S.C.A. § 6982(m)(1)(A) to (G).

[7] "Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas and Geothermal Energy," EPA/530-SW-88-003 (December 1987), at VIII-11, *hereinafter* ("Report to Congress").

[8] "Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas and Geothermal Energy," EPA/530-SW-88-003 (December 1987), at VIII-11, *hereinafter* ("Report to Congress").

members determine if a waste fits into the exemption.[9] EPA published its findings in 1988, elaborating that Subtitle C regulations present an "unusually large number of highly detailed statutory requirements" that would be too costly and unnecessary for the safe management of E&P Waste.[10] Since the initial determination, EPA has reviewed the need for E&P Waste regulation under Subtitle C and consistently found no such regulation is necessary.[11]

### 2. Applying the Exploration and Production Waste Statutory Exemption

## § 29:95 The Bentsen Amendment—EPA Guidance on categorizing E&P waste

Any person who generates a solid waste must determine whether it is a hazardous waste and whether it falls within the E&P Waste statutory exemption. The procedure for making this determination is both important and complex.[1] The statutory exemption of E&P Waste does not specifically define "drilling water, production wastes, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy" covered by the exemption.[2] While EPA incorporates the statutory exemption into its regulations excluding certain types of solid waste as hazardous waste,[3] EPA has never promulgated rules defining these terms.

EPA has issued a number of guidance documents categorizing E&P Waste as exempt and non-exempt with EPA paying particularly close attention to "primary field operations" as a means of differentiating exempt E&P Waste from waste generated during transport or from downstream manufacturing and processing activities. In the 1987 report to Congress, EPA indicated that "primary field operations" include "the primary, secondary, and tertiary production of oil or gas" and *not* wastes generated by transportation.[4] Exempt E&P Wastes must also be "uniquely associated with exploration, development, and production" operations. EPA guidance defines this as waste "generated from a material or procedure that is necessary to locate and produce crude oil or natural gas. . .[or] only occurs during the exploration and production of crude oil or natural gas."[5] This means that not all wastes produced during the exploration, development and production of crude oil or natural gas are automatically exempt from regulation as hazardous waste.[6]

For crude oil exploration, development and production operations, EPA guidance

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[9]"Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas and Geothermal Energy," EPA/530-SW-88-003 (December 1987), at VIII-11, II-18, *hereinafter* ("Report to Congress").

[10]54 Fed. Reg. 25466, 25456.

[11]EPA most recently reviewed state and federal regulations governing E&P Waste in compliance with a Consent Decree entered by EPA and Environmental Integrity Project. *See* Environmental Integrity Project v. McCarthy, No. 16-824(JDB), Consent Decree (D.D.C. Dec 28, 2016).

**[Section 29:95]**

[1]For further discussion regarding hazardous waste determinations, *see* Law of Environmental Protection, Fall 2019 Edition, Environmental Law Institute, Chapter §§ 14:24-32.

[2]42 U.S.C.A. § 6921(b)(2)(A).

[3]40 C.F.R. § 261.4(b)(5) (2021).

[4]Report to Congress at II-19.

[5]*Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations*, EPA530-K-01-004 (2002) at 22, *hereinafter* ("E&P Guidance").

[6]For example, wastes such as solvents used to clean surface equipment or machinery is not exempt, because these same cleaning activities are not uniquely associated with the exploration and production of crude oil or natural gas. However, if the same cleaning solvent were used in a well, it would be exempt because the well is unique to production operations. *Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations*, EPA530-K-01-004 (2002) at

indicates "primary field operations" include "activities occurring at or near the wellhead, but prior to the transport of oil from an individual field facility or a centrally located facility to a carrier for transport to a refinery."[7] Specific examples of these activities include "crude oil processing, such as water separation, demulsifying, degassing, and storage tank batteries *associated with a specific well or wells*."[8] This exemption does not apply to wastes created by the transport of product from the exploration and production sites or downstream refining, but does cover wastes generated directly by exploration and production operations which are then moved off-site for further treatment or disposal. As EPA explained in its 1993 guidance, "wastes derived from the treatment of an exempt waste, including any recovery of product from an exempt waste, generally remain exempt from the requirements of RCRA Subtitle C.[9]

For natural gas exploration, development and production operations, "primary field operations" include "those activities occurring at or near the wellhead or at the gas plant but prior to that point at which the gas is transferred from an individual field facility, a centrally located facility, or a gas plant to a carrier for transport to market."[10] Because natural gas typically requires processing to remove impurities before entering the sales line, EPA considers gas plants part of primary field operations regardless of their distance from the wellhead.[11]

To assist industry members in interpreting these definitions, EPA has provided two "rule of thumb" questions to consider when categorizing E&P Wastes:

1. Has the waste come from down-hole, i.e., was it brought to the surface during crude oil or natural gas exploration, development and production operations?
2. Has the waste otherwise been generated by contact with the oil and gas production stream during the removal of produced water or other contaminants from the product?[12]

If the answer to *either* of these questions is yes, the waste is likely a Bentsen waste exempt from regulation under Subtitle C of RCRA.

## § 29:96 EPA List of Exempt and Non-Exempt E&P Waste

In addition to providing a framework for case-by-case waste determination, EPA has identified wastes the agency categorizes as exempt and non-exempt:[1]

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18, *hereinafter* ("E&P Guidance").

[7] *Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations*, EPA530-K-01-004 (2002) at Report to Congress at II-18, *hereinafter* ("E&P Guidance").

[8] E&P Guidance at 7.

[9] Clarification of the Regulatory Determination for Wastes From the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy, 58 Fed. Reg. 15284, 15285 (March 22, 1993).

[10] Report to Congress at II-18.

[11] E&P Guidance at 7.

[12] E&P Guidance at 8.

**[Section 29:96]**

[1] E&P Guidance at 10–11.

| Exempt Wastes | Non-Exempt Wastes |
|---|---|
| • Produced water<br>• Drilling fluids<br>• Drill cuttings<br>• Rigwash<br>• Drilling fluids and cuttings from offshore operations disposed of onshore<br>• Geothermal production fluids<br>• Hydrogen sulfide abatement wastes from geothermal energy production<br>• Well completion, treatment, and stimulation fluids<br>• Basic sediment, water, and other tank bottoms from storage facilities that hold product and exempt waste<br>• Accumulated materials such as hydrocarbons, solids, sands, and emulsion from production separators, fluid treating vessels, and production impoundments<br>• Pit sludges and contaminated bottoms from storage or disposal of exempt wastes<br>• Gas plant dehydration wastes, including glycol-based compounds, glycol filters, and filter media, backwash, and molecular sieves<br>• Workover wastes<br>• Cooling tower blowdown<br>• Gas plant sweetening wastes for sulfur removal, including amines, amine filters, amine filter media, backwash, precipitated amine sludge, iron sponge, and hydrogen sulfide scrubber liquid and sludge<br>• Spent filters, filter media, and backwash (assuming the filter itself is not hazardous and the residue in it is from an exempt waste stream)<br>• Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment prior to transportation<br>• Produced sand<br>• Packing fluids<br>• Hydrocarbon-bearing soil<br>• Pigging wastes from gathering lines<br>• Wastes from subsurface gas storage and retrieval<br>• Constituents removed from produced water before it is injected or otherwise disposed of<br>• Liquid hydrocarbons removed from the production stream but not from oil refining<br>• Gases from the production stream, such as hydrogen sulfide and carbon dioxide, and volatilized hydrocarbons<br>• Materials ejected from a producing well during blowdown<br>• Waste crude oil from primary field operations<br>• Light organics volatilized from exempt wastes in reserve pits, impoundments, or production equipment | • Unused fracturing fluids or acids<br>• Gas plant cooling tower cleaning wastes<br>• Painting wastes<br>• Waste solvents<br>• Oil and gas service company wastes such as empty drums, drum rinsate, sandblast media, painting wastes, spent solvents, spilled chemicals, and waste acids<br>• Vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste<br>• Refinery wastes<br>• Liquid and solid wastes generated by crude oil and tank bottom reclaimers<br>• Used equipment lubricating oils<br>• Waste compressor oil, filters, and blowdown<br>• Used hydraulic fluids<br>• Waste in transportation pipeline related pits<br>• Caustic or acid cleaners<br>• Boiler cleaning wastes<br>• Boiler refractory bricks<br>• Boiler scrubber fluids, sludges, and ash<br>• Incinerator ash<br>• Laboratory wastes<br>• Sanitary wastes<br>• Pesticide wastes<br>• Radioactive tracer wastes<br>• Drums, insulation, and miscellaneous solids |

Many of the waste determinations identified by EPA provide clarity to the limits of the E&P Waste exemption. For example, unused products, such as unused fracking fluids, waste solvents or used oil from equipment, are *not* exempt from regulation as a hazardous waste if disposed because they are not "uniquely associated" with the exploration and production operations.[2] Similarly, the exemption of pigging wastes stemming from *gathering* lines but not *transportation* lines emphasizes the difference between field and transportation activities. These slight distinctions highlight the importance EPA places on the waste being both associated with a primary field operation and uniquely associated with the exploration, development, or production of crude oil or natural gas. Before disposing of any waste generated at exploration and production sites, operators should carefully review EPA and state applicable guidance to ensure they are managing the waste appropriately. The failure to properly manage and dispose of the waste can lead to significant civil penalties and potentially criminal sanctions.

## § 29:97 E&P Waste Mixtures

In determining a waste's status as exempt or non-exempt, EPA guidance also highlights the dangers of mixing exempt E&P Waste with other waste which may not fall into the exemption.[1] Recall, the Bentsen amendment only exempts E&P Wastes from regulation as hazardous wastes under RCRA Subtitle C; it does not ad-

[2] E&P Guidance at 19.

**[Section 29:97]**

[1] E&P Guidance at 13–17.

dress mixtures of exempt and non-exempt waste. EPA, however, maintains authority to regulate mixtures of exempt and non-exempt wastes to ensure protection of human health and the environment. Three possible mixtures implicate the E&P Waste statutory exemption:

1. When an exempt E&P Waste is mixed with another exempt waste or a non-hazardous waste, the mixture remains exempt.
2. When an exempt E&P Waste is mixed with a non-exempt, characteristic hazardous waste, and the mixture does not exhibit any hazardous characteristic exhibited by the non-exempt waste, the mixture remains exempt.[2] However, if the mixture exhibits a hazardous characteristic exhibited by the non-exempt characteristic waste, the waste is considered a non-exempt characteristic hazardous waste and subject to RCRA Subtitle C.
3. When an exempt E&P Waste is mixed with a listed hazardous waste, the mixture is considered a listed hazardous waste and subject to RCRA Subtitle C.[3]

Operators of oil and gas production facilities and gas processing facilities need to be careful not to mix waste streams or could risk losing the Bentsen exemption all together. Even small amounts of listed hazardous wastes (spent solvents, lubricants or unused fracking fluids) is enough to lose the exemption. When bringing chemicals or other products to the site, a good rule of thumb is to separately manage those chemicals and products.

### § 29:98 Regulation of E&P Waste under RCRA

The Bentsen amendment, while excluding E&P Wastes from regulation as hazardous wastes under RCRA Subtitle C, did not extend the exemption to any other provisions of RCRA. Because the exemption only applies to RCRA Subtitle C, all E&P Waste which meet the definition of "solid wastes" remain subject to regulation under RCRA Subtitle D as well as other provisions under RCRA.[1] Subtitle D regulations typically impose less stringent requirements on waste management.[2]

RCRA defines "solid waste" as "any garbage, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations, and from community activities."[3] EPA interprets this definition as "any discarded material that is not excluded under § 261.4(a)."[4] RCRA Subtitle D bans open dumping of solid wastes and sets minimum federal criteria for waste disposal methods.[5] The D.C. Circuit in *American Iron and Steel Institute v. EPA* found that E&P Wastes are only exempt from regulation as "hazardous," because exempting the wastes from *all* provisions of RCRA would "elevate Bevill-Bentsen wastes to a privileged position

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[2] Note that EPA has taken the position that mixing non-hazardous or exempt waste with characteristic hazardous waste may be considered treatment for purposes of EPA's hazardous waste regulations and could separately require a permit.

[3] E&P Guidance at 17.

**[Section 29:98]**

[1] American Iron and Steel Institute v. U.S. E.P.A., 886 F.2d 390, 396, 30 Env't. Rep. Cas. (BNA) 1393, 20 Envtl. L. Rep. 20027 (D.C. Cir. 1989).

[2] American Petroleum Institute v. U.S. E.P.A., 216 F.3d 50, 54, 50 Env't. Rep. Cas. (BNA) 1833, 30 Envtl. L. Rep. 20686 (D.C. Cir. 2000), as amended, (Aug. 18, 2000).

[3] 42 U.S.C.A. § 6903(27).

[4] 40 C.F.R. § 261.2(a)(1) (2021).

[5] 42 U.S.C.A. §§ 6941 to 6949a.

above all other nonhazardous solid wastes."[6]

Improper management of E&P Waste can trigger additional RCRA provisions, including RCRA citizen suit provisions and corrective action in addition to claims arising under state law. RCRA § 7002 states that:[7]

Any person may commence a civil action on his own behalf:

> against any person . . . who is alleged to be in violation of any permit, standard, regulation, condition, requirement, prohibition, or order which has become effective pursuant to this chapter; or
>
> against any person . . . and including any past or present generator, past or present transporter, or past or present owner or operator of a treatment, storage, or disposal facility, who has contributed or who is contributing to the past or present handling, storage, treatment, transportation, or disposal of any **solid** or hazardous waste which may present an imminent and substantial endangerment to health or the environment.[8]

The citizen suit provisions are not limited to only the handling and management of hazardous wastes.[9] Further, courts have liberally interpreted the terms "imminent and substantial endangerment to health or the environment."[10] Courts have the authority to grant injunctive relief and can award costs and fees.[11]

In addition, RCRA § 3004(u) requires "corrective action for all releases of hazardous waste or constituents from any solid waste management unit at a facility seeking a permit."[12] The D.C. Circuit held in *American Iron and Steel* that because this provision pertains to hazardous *constituents* as well as hazardous waste, the provision applies to constituents which migrated from E&P Waste.[13]

### 3. Regulation of E&P Waste Under State and Other Federal Law

## § 29:99 State regulation of E&P waste

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[6] *American Iron & Steel*, at 394–5.

[7] 42 U.S.C.A § 6972.

[8] (emphasis added).

[9] For further discussion regarding the citizen provisions under RCRA *see* Law of Environmental Protection, Fall 2019 Edition, Environmental Law Institute, Chapter 9:211.

[10] *See* Maine People's Alliance And Natural Resources Defense Council v. Mallinckrodt, Inc., 471 F.3d 277, 63 Env't. Rep. Cas. (BNA) 1737 (1st Cir. 2006) (after first noting that at least four of its sister circuits have also construed the terms liberally, the court did so as well holding that "reasonable prospect of future harm" is adequate so long as the threat, as opposed to the harm, is near-term, and involves potentially serious harm, but not need be an emergency situation and does not require a showing an immediate threat of grave harm); Liebhart v. SPX Corporation, 917 F.3d 952, 959, 103 Fed. R. Serv. 3d 215 (7th Cir. 2019) ("imminent and substantial endangerment to health" does not require existing harm, or even threatened irreparable harm. It merely require a plaintiff to show that contaminants on the property are seriously dangerous to human health or will be, given prolonged exposure over time); Price v. U.S. Navy, 39 F.3d 1011, 1019, 39 Env't. Rep. Cas. (BNA) 1673, 30 Fed. R. Serv. 3d 854, 25 Envtl. L. Rep. 20177 (9th Cir. 1994) (holding that RCRA does not require actual harm, but threatened or potential harm will suffice). U.S. v. Conservation Chemical Co., 619 F. Supp. 162, 24 Env't. Rep. Cas. (BNA) 1008, 16 Envtl. L. Rep. 20193 (W.D. Mo. 1985) (endangerment need not be immediate to be imminent; specific quantification of the endangerment not required, rather a consideration of all factors is proper based on the unique facts of each case; and, if an error is to be made in applying the endangerment standard, it must be made in favor of protecting the environment); Paper Recycling, Inc. v. Amoco Oil Co., 856 F. Supp. 671, 678, 40 Env't. Rep. Cas. (BNA) 2043, 25 Envtl. L. Rep. 20135 (N.D. Ga. 1993), on reconsideration, (Dec. 14, 1993) ("imminent and substantial endangerment" to "health or the environment" requires only a showing that a risk of threatened harm is present, not that actual harm will immediately occur).

[11] 42 U.S.C.A. § 6972(e).

[12] 42 U.S.C.A. § 6924(u). For further discussion regarding the corrective active provisions under RCRA *see* Law of Environmental Protection, Fall 2019 Edition, Environmental Law Institute, Chapter 14.

[13] *American Iron & Steel*, 886 F.2d at 395.

A major motivating factor in the Bentsen amendment exemption for E&P Waste was the state and federal regulations existing at the time Congress passed the amendment. Under RCRA, states may implement their own waste management programs so long as those programs are as stringent as the federal regulations.[1] States may adopt more stringent requirements if they desire. As part of the decision not to regulate E&P Waste under RCRA Subtitle C, EPA relied on the state regulatory programs which manage E&P Waste.

In 2019, EPA re-visited state regulation of E&P Wastes to ensure state regulations adequately address the technological developments in the field of hydraulic fracturing.[2] In its study, EPA reviewed regulations from 28 of the 34 states with reported production of oil and gas, as tracked by the Energy Information Administration.[3] EPA found that the 11 highest oil and gas producing states account for 90% of the United States oil and gas production and,[4] as such, have regulatory programs tailored specifically to E&P Waste. EPA found the remaining states generally have more general programs addressing E&P Waste under the framework of other solid wastes. As further discussed in the 2019 State Report, the majority of high production states regulate E&P Waste management and disposal through imposing: protection of groundwater, surface water, floodplains and endangered species; waste management location restrictions and requirements to protect these resources;; storage tank requirements including construction, containment and monitoring; pit construction, operation, and closure requirements; spill notification requirements and corrective action requirements; restrictions or controls on venting or flaring natural gas; treating produced water prior placement in produced water pits; promoting proper reuse and recycling including beneficial re-use and land application; testing of wastes prior to disposal including testing for radionuclides and radioisotopes; and waste minimization and best practices.[5]

A comprehensive review of the state regulations for managing E&P Waste is beyond the scope of this Chapter. Oil and gas practitioners should carefully review their respective state laws regarding the management of E&P Waste. As noted above, non-exempt wastes are subject to RCRA Subtitle C and must be properly characterized, managed, and disposed.

## § 29:100 Applicability of additional federal statutes

RCRA is not the only statutory scheme which governs E&P Wastes, and E&P Waste is not exempt from regulation by alternative federal statutes simply because they are exempt from regulation as a hazardous waste. Owners and operators can be held liable under the Oil Pollution Act for releases of E&P Waste, including damages to natural resources.[1] E&P wastes may also be subject to the Clean Water Act's National Pollutant Discharge Elimination System permitting requirements as they pertain to the release of a pollutant from a point source into a water of the United

**[Section 29:99]**

[1] 42 U.S.C.A. § 6926.

[2] Management of Exploration, Development and Production Wastes: Factors Informing a Decision on the Need for Regulatory Action (April 2019), *hereinafter* ("2019 State Report").

[3] Management of Exploration, Development and Production Wastes: Factors Informing a Decision on the Need for Regulatory Action at 6-29 (April 2019), *hereinafter* ("2019 State Report").

[4] TX, PA, AK, OK, ND, CO, WY, NM, LA, OH, WV.

[5] 2019 State Report, at 6-30, 31.

**[Section 29:100]**

[1] 33 U.S.C.A. §§ 2701 et seq.

States;[2] and the Safe Drinking Water Act's underground injection control program.[3]

### § 29:101 Conclusion

EPA continues to exempt E&P Waste from regulation under RCRA Subtitle C. While EPA has released limited guidance on waste categorization, state regulations continue to form the basis of E&P Waste regulation.

## C. CLEAN WATER ACT

Water is both an integral part of oil and gas operations and a produced waste. Produced water contains TDS, chloride, bromide, metals, and radioactive materials that may be harmful to human and environmental health.[1] The Clean Water Act (CWA) and its state proxy programs govern discharges of pollutants into the "waters of the United States," including industrial wastewater, stormwater, and runoff from construction activities from oil and gas operations.[2]

### § 29:102 Section 402—NPDES Regulation (33 U.S.C. § 1342)

Of the regulated oil and gas wastes, *produced water* is the largest source by volume. Produced water is the fluid or brine "brought up by the hydrocarbon-bearing strata during the extraction of oil and gas and includes, where present, formation water, injection water, and any chemicals added downhole or during drilling, production or maintenance processes."[1] The ratio and chemical makeup of produced water can vary drastically from formation to formation. Most of this water is regulated under the Safe Drinking Water Act because it is disposed of in underground injection wells used to recover more oil.[2] The portions of produced water disposed into surface waters or sent to treatment facilities are regulated under CWA § 402.[3]

### § 29:103 State programs

States may administer their own NPDES permit programs and submit them to the EPA for approval.[1] As of March 2021, 46 states and the Virgin Islands have been delegated the authority to administer at least a partial NPDES program. New

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[2]33 U.S.C.A. § 1342.

[3]42 U.S.C.A. §§ 300f et seq.

[1]Clean Water Action, Clean Water Act Regulation of Oil and Gas Wastewater Discharges: A Call for Improved Oversight and Transparence (January 2020), https://cleanwateraction.org/sites/default/files/docs/publications/Report%20—%20Clean%20Water%20Act%20Regulation%20of%20Oil%20and%20Gas%20Wastewater%20—%20Clean%20Water%20Action%20Jan%202020.pdf.

[2]*See* Chapter 13 of this treatise (overview of the CWA).

**[Section 29:102]**

[1]U.S. EPA, Summary of Input on Oil and Gas Extraction Wastewater Management Practices Under the Clean Water Act 7 (May 2020), *available at* https://www.epa.gov/sites/production/files/2020-05/documents/oil-gas-final-report-2020.pdf [hereinafter Summary of Wastewater Management Practices].

[2]*See* § 14:70 of this treatise (Underground injection control program).

[3]33 U.S.C. § 1342; South Florida Water Management Dist. v. Miccosukee Tribe of Indians, 541 U.S. 95, 102, 124 S. Ct. 1537, 158 L. Ed. 2d 264, 58 Env't. Rep. Cas. (BNA) 1001, 34 Envtl. L. Rep. 20021 (2004); U.S. EPA. Groundwater Protection Council, Produced Water Report 15 (June 2019), *available at* https://www.gwpc.org/sites/gwpc/uploads/documents/Research/Produced_Water_Full_Report___Digital_Use.pdf [hereinafter Produced Water Report] [*See* § 13:63 of this treatise.

**[Section 29:103]**

[1]Produced Water Report, *supra* note 5, at 16. In Massachusetts, New Hampshire, New Mexico, Washington D.C., U.S. territories, and federal and tribal trust lands the EPA issues the NPDES permits. All other have states have state entities that have been delegated by the EPA to issue their

Mexico, Massachusetts, New Hampshire, and Washington, D.C. do not have an authorized state program. Oklahoma and Texas have partial programs, which do not include permitting for activities associated with the exploration, development, or production of oil, gas, or geothermal resources, including transportation of crude oil or natural gas by pipeline. The EPA is the permitting authority for these activities in Texas and Oklahoma.[2] No Tribe currently has TAS approval to operate the NPDES permit program.[3]

## § 29:104 NPDES Permits

NPDES permits can be issued individually to authorize and establish regulatory controls from a single facility, or they can be issued generally to permit discharges from multiple facilities with similar operations and/or pollutants.[1] General permits are written to cover one or more categories or subcategories of discharges, sludge use, disposal practices, or facilities described in the permit.[2] An individual permit may be required if the discharger is a significant pollutant contributor, a status which is determined by considering: (1) the location of the discharge with respect to waters of the United States; (2) the volume of the discharge; (3) the quantity and nature of the pollutants discharged; and (4) other relevant factors.[3] NPDES regulation specifically directs the Regional Administrator to issue general permits to offshore oil and gas facilities, but this is not applicable to state programs.[4] Further, where the offshore facility is in an area of biological concern, for which separate permit conditions are required, EPA may issue separate general permits, individual permits, or both to accommodate any additional required permit conditions.[5] The Regional Administrator always has the ability to require an individual permit.[6]

A NPDES permit will specify both narrative and numerical limits on one or more regulated pollutants determined by technology- and water-quality-based standards.[7] First, the permit writer must determine a pollutant's minimum discharge standard or effluent limitation guidelines (ELGs).[8] This is done by identifying the best available technology that is economically achievable for that industry and setting regulatory requirements based on the performance of that technology.[9] Different levels of control are established based on whether the pollutant is a priority pollutant,

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own permits. *See* § 13:46 of this treatise

[2]U.S. EPA, *National Pollutant Discharge Elimination System: NPDES State Program Authority*, https://www.epa.gov/npdes/npdes-state-program-authority (last visited June 22, 2021).

[3]U.S. EPA, *Tribes Approved for Treatment as a State (TAS)*, Tribes Approved for Treatment as a State (TAS) | Environmental Protection in Indian Country | US EPA (last visited June 21, 2021).

**[Section 29:104]**

[1]U.S. EPA, *National Pollutant Discharge Elimination System (NPDES)*, https://www.epa.gov/npdes/npdes-state-program-authority (last visited June 22, 2021); PRODUCED WATER REPORT, *supra* note 5, at 18.

[2]40 C.F.R. § 122.28 (2021).

[3]40 C.F.R. § 122.28(b)(3)(i)(G) (2021).

[4]40 C.F.R. § 122.28(c) (2021). There is no similar regulation for onshore facilities. As discussed above, discharge is generally prohibited from onshore facilities.

[5]40 C.F.R. § 122.28(c) (2021). *See* § 14:70 of this treatise; 122.28(c)(1).

[6]40 C.F.R. § 122.28(c)(3) (2021).

[7]40 C.F.R. § 122.28(c)(3) (2021).

[8]These are also known as "technology-based effluent limitations." *See* 40 C.F.R. § 122.44 (2021).

[9]SUMMARY OF WASTEWATER MANAGEMENT PRACTICES, *supra* note 3, at 11; *See* §§ 13:52 to 13:67 of this treatise.

conventional pollutant, or a nonconventional pollutant.[10] Pollution guidelines come in several forms: (1) best practicable control technology (BPT); (2) best conventional pollutant control technology (BCT); (3) best available technology economically achievable (BAT); and (4) best available demonstrated control technology for new sources, or new source performance standards (NSPS).[11] Which guideline is applicable will depend on whether a discharge is existing or new and whether it is direct or indirect.[12] A direct discharge is just a point source that discharges pollutants directly to the waters of the United States; an indirect discharge is "a nondomestic discharg[e that] introduc[es] 'pollutants' to a 'publicly owned treatment works.' "[13] Only direct discharges are governed by BPT, BAT, BCT, and NSPS standards. Indirect discharges are governed by pretreatment standards established under section 307 of the CWA.[14] New sources face more immediate compliance deadlines than existing sources—if the EPA establishes new ELG standards, existing dischargers only need to comply with the standards current when their NPDES permits are issued, reissued or modified.[15]

The EPA publishes national ELGs for the oil and gas extraction industry in the Code of Federal Regulations at 40 C.F.R. Part 435.[16] These regulations are subcategorized—onshore, offshore, agricultural and wildlife water, coastal, and stripper[17]—with varying guidelines assigned to each subpart. Each subcategory may have specific, additional requirements. For example, the specifications range from zero allowable discharge for onshore wells to no national ELG for stripper wells.[18] The onshore subcategory contains pretreatment standards for new and existing wastewater sources from unconventional oil and gas extraction.[19] The coastal subcategory contains pretreatment standards for sources that introduce pollutants into a POTW. These pretreatment standards allow no amount of discharge of produced water, workover and completion fluids, produced sand, or deck drainage.[20]

ELGs serve as a baseline, but they do not always ensure that all designated ben-

[10] Summary of Wastewater Management Practices, *supra* note 3, at 11.

[11] Summary of Wastewater Management Practices, *supra* note 3, at 12.

[12] Summary of Wastewater Management Practices, *supra* note 3, at 12.

[13] 40 C.F.R. § 122.2 (2021).

[14] There are two pretreatment standards—pretreatment standards for new sources (PSNS) and pretreatment standards for existing sources (PSES). Both standards are national, uniform, technology-based standards that are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. PSNS should be issued at the same time as NSPS. Under PSNS, new indirect dischargers are required to incorporate the best available demonstrated technologies within 90 days of commencing discharge. EPA, *Learn About Effluent Guidelines*, https://www.epa.gov/eg/learn-about-effluent-guidelines (last visited June 23, 2021).

[15] Memorandum from Linda Boornazian, EPA, New Source Dates for Direct and Indirect Dischargers at 2–3 (Sept. 28, 2006), *available at* https://www3.epa.gov/npdes/pubs/newsource_dates.pdf. A new source discharge is any building, structure, or installation from which there is or may be a discharge of pollutants, the construction of which commenced after promulgation of standards under § 306 of the CWA or after proposal of such standards. 40 C.F.R. § 122.22.

[16] Memorandum from Linda Boornazian, EPA, New Source Dates for Direct and Indirect Dischargers at 2–3 (Sept. 28, 2006), *available at* https://www3.epa.gov/npdes/pubs/newsource_dates.pdf; 40 C.F.R. § 435 (2021).

[17] A stripper well is "any oil or natural gas well whose maximum daily average oil production does not exceed 15 barrels of oil, or any natural gas well whose maximum daily average gas production does not exceed 90 thousand cubic feet of gas [] per day, during any 12-month consecutive time period." Nat'l Stripper Well Assoc., *What is a Stripper Well?* Stripper Wells | National Stripper Well Association (nswa.us) (last visited June 21, 2021).

[18] 40 C.F.R. § 435 (2021). However, produced waters may be discharged to surface waters west of the 98th meridian under Subpart E.

[19] 40 C.F.R. § 435.33 (2021).

[20] 40 C.F.R. § 435.46 (2021).

eficial uses of the surface water will be protected. Thus, the permit writer may take a second step and consider more stringent water-quality-based effluent limits (WQBELs) when drafting NPDES permits. These limits may be numerical or narrative ("e.g., no toxic substances in toxic quantities"). To establish these limits, the permit writer must consider the "designated beneficial use of the water body; the amount of the pollutant in the effluent, toxicity, and assimilative capacity; and, where appropriate, dilution in the receiving water (including discharge conditions and water column properties)."[21]

## § 29:105 Off-Site Waste Treatment

Analogous treatment standards will apply if oil and gas wastewater is sent to a POTW or a centralized waste treatment facility (CWT). CWTs that accept produced water are also subject to ELGs.[1] Produced water is required to go through the CWT before it may be sent to a municipal wastewater treatment facility.[2] The waste treatment must meet one of three standards: pretreatment standards for existing sources (PSES), pretreatment standards for new sources (PSNS), or NSPS standards.[3] These processing facilities are regulated as off-site facilities.[4] Thus, these regulations will not apply unless the discharge facility is considered off-site. The EPA defines "site" as "the land or water area where any 'facility or activity' is physically located."[5] A "facility or activity" is defined as any NPDES "point source" or any facility or activity that is subject to regulation under the NPDES program.[6] Despite these definitions, it is still somewhat unclear what processing facility would be treated as off-site. In a recent compliance guidance document, the EPA has defined "site" for the purpose of gas drilling activities as: "The land identified in the drilling permit; including the location of wells, access roads, lease areas, and any lands where the facility is conducting its exploratory, development or production activities, or adjacent lands used in connection with the facility or activity."[7] Using that definition, any land outside of those boundaries would be considered off-site and thus subject to the POTW and CWT regulations.

## § 29:106 Oil and gas stormwater discharge

Aside from wastewater discharge, industrial stormwater dischargers are typically required to apply for an individual permit or seek coverage under a general stormwater permit. Operators of oil and gas explorations, production, processing, treatment operation, or transmission facility are not required to submit an application for an individual permit so long as any stormwater runoff is not contaminated with "overburden, raw material, intermediate products, finished product, byproduct, or waste products located on the site of such operations."[1] These limitations apply

[21] PRODUCED WATER REPORT, *supra* note 6 at 19.

**[Section 29:105]**

[1] PRODUCED WATER REPORT, *supra* note 6 at 15–18.

[2] PRODUCED WATER REPORT, *supra* note 6 at 15.

[3] 40 C.F.R. §§ 437.24 to 26 (2021); SUMMARY OF WASTEWATER MANAGEMENT PRACTICES, *supra* note 3, at 12.

[4] 40 C.F.R. § 437.1(a)(1) (2021).

[5] 40 C.F.R. § 122.2 (2021).

[6] 40 C.F.R. § 122.2 (2021).

[7] SUMMARY OF WASTEWATER MANAGEMENT PRACTICES, *supra* note 3, at 16.

**[Section 29:106]**

[1] 33 U.S.C. § 1342(l)(2).

even if the oil and gas activities are considered "construction activities."[2] The exception, however, does not apply if the facility (a) "[h]as had a discharge of storm water resulting in the discharge of a reportable quantity for which notification is or was required pursuant to 40 C.F.R. 117.21"; (b) "[h]as had a discharge of storm water resulting in the discharge of a reportable quantity for which notification is or was required pursuant to 40 C.F.R. 110.6 at any time since November 16, 1987"; or (c) "[c]ontributes to a violation of a water quality standard."[3] But the third water-quality-standard exception does not apply to discharges of sediment from "construction activities associated with oil and gas exploration."[4] In other words, an individual permit is *not* required if the WQS violation arises from discharges of sediment caused by construction activities.

### § 29:107 Section 401—Water Quality Certificates (33 U.S.C. § 1341)

Under § 401 of the CWA, a federal agency may not issue any permit or license to conduct any activity that may result in any discharge into waters of the United States unless a § 401 water quality certification is issued by the state and/or authorized tribe where the discharge would originate, verifying compliance with water quality requirements.[1]

States and tribes have used § 401 authority to deny federally permitted/licensed energy projects. For example, in 2017 the state of Washington denied a § 401 water quality certification for a joint aquatic resource permit application from Millennium Bulk Terminals to build a coal export terminal along the Columbia River. The state cited unavoidable harm to the Columbia River and surrounding environment and a failure to provide reasonable assurance that Millennium would, or even could, implement the identified mitigation steps necessary to protect clean water.[2] New York and New Jersey similarly denied a § 401 water quality certification for a FERC licenses needed to build a fracked natural gas transmission pipeline, citing potential harms to water quality, threatened marine life, and the need to transition away from fossils fuels and address climate change.[3]

It was in response to actions like those and at the behest of the Trump administra-

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[2]40 C.F.R. § 122.26(a)(2)(ii) (2021).

[3]40 C.F.R. § 122.26(c)(1)(iii) (2021); Delaware Riverkeeper Network v. Sunoco Pipeline L.P., 2020 WL 1888954, at *10 (E.D. Pa. 2020) ("The 'exception to the exemption' covers discharges from only a 'facility.' ").

[4]40 C.F.R. § 122.26(a)(2)(ii) (2021).

**[Section 29:107]**

[1]EPA, *Basic Information on CWA Section 401 Certification*, https://www.epa.gov/cwa-401/basic-information-cwa-section-401-certification (last visited June 23, 2021). *See* § 13:37 of this treatise.

[2]Letter from Maia D. Bellon, Wash. Dep't of Ecology, to Kristin Gains, Millennium Bulk Terminals (Sept. 26, 2017); DEP'T OF ECOLOGY, STATE OF WASH., *Millennium Bulk Terminals Longview*, https://ecology.wa.gov/Regulations-Permits/SEPA/Environmental-review/SEPA-at-Ecology/Millennium (last visited Nov. 2, 2020). Specifically, the Washington Department of Ecology found that the project would: (1) require driving 537 pilings into the riverbed; (2) destroy 24 acres of wetlands; (3) eliminate five acres of aquatic habitat; (4) increase ship traffic on the Columbia River by 1,680 trips a year; and (5) impair tribal access to protected fishing sites. These findings along with other broader issues in the project's EIS, all led to the rejection of the water quality permit and other permits requested by Millennium. *See* Letter from Maia D. Bellon, Wash. Dep't of Ecology, to Kristin Gains, Millennium Bulk Terminals (Sept. 26, 2017); *see also* Millennium Bulk Terminals-Longview, LLC v. State, 12 Wash. App. 2d 1060, 2020 WL 1651475 (Div. 2 2020), review denied, 195 Wash. 2d 1032, 468 P.3d 615 (2020).

[3]Letter from Daniel Whitehead, Dir., Div. of Env't Permits, to Joseph Dean, Manager, Env't Health & Safety, Transcon. Gas Pipe Line Co., LLC (May 15, 2020), *available at* https://www.dec.ny.gov/docs/permits_ej_operations_pdf/nesewqcdenial05152020.pdf; Letter from Christopher Jones for Diane Dow, Dir. of Div. of Land Use Regul., to Tim Powell, Transcon. Gas Pipe Line Co. (May 15, 2020), *available at* https://www.nrdc.org/sites/default/files/media-uploads/new_jersey_dep_nese_denial._may_15_2020.pdf; *see also* Rob Friedman, *New York State Rejects the Williams Fracked Gas Pipeline*, EXPERT

tion that the EPA revised its § 401 certification regulations to address scope and timing issues raised by commenters, the regulated community, and permitting agencies. The revised rule limits the scope of the § 401 certification to "assuring that *a discharge* from a Federally licensed or permitted activity will comply with water quality requirements."[4] Proponents of the new rule assert that the scope of authority afforded to states is consistent with CWA statutory language and is necessary to rein in states that are improperly using their § 401 certification authority to condition or deny a permit, which in turn results in the failure of entire projects. Recently, the American Petroleum Institute and the Natural Gas Association of America won a motion to intervene on behalf of the EPA in a suit brought by environmental advocacy organizations, states, tribes, and other environmental group to challenge the new rule.[5] The intervening oil and gas parties argued that prior to the new rule, states had improperly used § 401 to delay approving oil and gas projects based on "non-water quality considerations, such as preferences regarding energy policy[.]"[6] The case is ongoing in a California district court. The Biden administration has also targeted this rule for reevaluation and has announced its intent to revise the rule.[7]

## § 29:108 Section 403—Ocean Discharge Criteria (33 U.S.C. § 1343)

Under § 403, a project proponent can obtain an NPDES permit authorizing discharges to the ocean, rather than to jurisdictional waters of the United States, if the applicant can satisfy additional discharge criteria.[1]

Section 403 NPDES permits affect offshore oil and gas exploration activities.[2] For example, in *Alaska Eskimo Whaling Commission v. United States Environmental Protection Agency*, the whaling community challenged a permit authorizing oil and gas exploration discharges in the Beaufort Sea.[3] The permit authorized the discharge of 13 waste streams in accordance with specific "effluent limitations, monitoring requirements, and other conditions" set forth in the permit. The permit imposed a seasonal limitation on discharge of water-based drilling fluids and drill

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BLOG, NRDC (May 15, 2020), https://www.nrdc.org/experts/rob-friedman/new-york-state-rejects-williams-fracked-gas-pipeline. Oregon has similarly denied certification for a § 404 permit for a liquified natural gas export facility. *See* Letter from Richard Whitman, Dir. Or. Dep't of Env't Quality, to Derek Vowels & Jordan Cove, Pac. Connector Gas Pipeline, and Tyler Kurg, Army Corp. of Engineers (May 6, 2019).

[4] *See* § 13:37 of this treatise.

[5] American Rivers v. Wheeler, 2020 WL 5993229, at *1 (N.D. Cal. 2020).

[6] Motion to Intervene at 1 (Sept. 4, 2020), American Rivers v. Wheeler, 2020 WL 5993229 (N.D. Cal. 2020), *available at* https://www.law360.com/articles/1307914/attachments/0. Stayed as of February 22, 2021. Order Granting Motion to Stay, American Rivers v. Wheeler (No. C 20-04636) (N.D. Cal. filed Feb. 22, 2021). Litigation is pending in multiple federal district courts. Delaware Riverkeeper Net. v. EPA (No. 20-cv-3412) (E.D. Pa. July 13, 2020); California v. Wheeler, No. 20-cv-04869 (N.D. Cal. July 21, 2020); South Carolina Coastal Conservation League v. Wheeler, No. 20-cv-03062 (D.S.C. Aug. 26, 2020); Suquamish Tribe v. Wheeler, No. 20-cv-06137 (N.D. Cal. Aug. 31, 2020).

[7] Exec. Order No. 13990, "Protecting Public Health & the Environment & Restoring Science to Tackle the Climate Crisis," 86 Fed. Reg. 7037 (Jan. 20, 2021), *available at* https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executive-order-protecting-public-health-and-environment-and-restoring-science-to-tackle-climate-crisis/; U.S. EPA, Press Release, *EPA Takes Action to Bolster State and Tribal Authority to Protect Water Resources* (May 27, 2021) *available at* https://www.epa.gov/newsreleases/epa-takes-action-bolster-state-and-tribal-authority-protect-water-resources-0 (last visited July 18, 2021).

**[Section 29:108]**

[1] *See* § 13:78 of this treatise.

[2] *See* Alaska Eskimo Whaling Com'n v. U.S. E.P.A, 791 F.3d 1088, 1090–91, 80 Env't. Rep. Cas. (BNA) 1789 (9th Cir. 2015).

[3] Alaska Eskimo Whaling Com'n v. U.S. E.P.A, 791 F.3d 1088, 1090–91, 80 Env't. Rep. Cas. (BNA) 1789 (9th Cir. 2015).

cuttings to accommodate the fall bowhead whale hunting season, and it required the permittees to monitor to the "maximum extent possible" for deflection of marine mammals when discharging water-based drilling fluids, drilling cuttings, and non-contact cooling water."[4] There, the Ninth Circuit found the permit conditions and the EPA's conclusions regarding degradation of the marine environment sufficiently supported by the record but the conclusion regarding non-contact cooling water was made in error. Thus, the court remanded for consideration of whether the non-contact cooling water will cause degradation of the marine environment and the effect or non-effect of this cooling water on the bowhead whale migration and subsistence whale hunting in the Beaufort Sea.[5]

### § 29:109 Section 404 Discharge of Dredge of Fill Material (33 U.S.C. § 1344)

Under 404, the Secretary of the Army Corps of Engineers (the Secretary) may, after notice and opportunity for public hearings, issue permits for the discharge of dredge or fill material into waters of the United States.[1] The Secretary may issue specific permits or general permits on a state, regional, or nationwide basis "for any category of activities involving discharges of dredged or fill material if the Secretary determines that the activities in such category are similar in nature, will cause only minimal adverse environmental effects when performed separately, and will have only minimal cumulative adverse effect on the environment."[2] General permits may not be issued for a duration of more than five years, and the Secretary may revoke or modify any permit for an activity that results in an adverse impact on the environment.[3]

One such permit, Nationwide Permit 12 (NWP 12), authorizes discharge of dredged or fill material into jurisdictional waters as required for the construction, maintenance, repair and removal of utility lines and associated facilities.[4] Oil and gas pipelines qualify as utility lines under NWP 12.[5] The Secretary reissued the NWP-12 in 2017 after a public notice and comment period.[6] When a project falls under a regional or nationwide permit, the evaluation guidelines are only applied once—when the general permits are issued.[7] Reissuance of a nationwide permit also requires a national-scale cumulative impact assessment in accordance with the National Environmental Policy Act (NEPA) and evaluation under the Endangered Species Act (ESA).[8]

To be covered under the NWP 12, a potential project may not result in the loss of greater than one-half acre of jurisdictional waters for each single and complete

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[4] Alaska Eskimo Whaling Com'n v. U.S. E.P.A, 791 F.3d 1088, 1090–91, 80 Env't. Rep. Cas. (BNA) 1789 (9th Cir. 2015).

[5] Alaska Eskimo Whaling Com'n v. U.S. E.P.A, 791 F.3d 1088, 1090–91, 1093, 80 Env't. Rep. Cas. (BNA) 1789 (9th Cir. 2015).

**[Section 29:109]**

[1] *See* §§ 13:100 to 115 of this treatise; 33 U.S.C. § 1344; Mingo Logan Coal Company Inc. v. U.S. Environmental Protection Agency, 70 F. Supp. 3d 151, 156, 79 Env't. Rep. Cas. (BNA) 2139 (D.D.C. 2014), judgment aff'd, 829 F.3d 710, 82 Env't. Rep. Cas. (BNA) 1933 (D.C. Cir. 2016).

[2] 33 U.S.C. § 1344(e)(1).

[3] 33 U.S.C. § 1344(e)(2).

[4] Optimus Steel, LLC v. U.S. Army Corps of Engineers, 492 F. Supp. 3d 701 (E.D. Tex. 2020) (citing 82 Fed. Reg. at 1985 to 86 (Jan. 6, 2017)).

[5] Optimus Steel, LLC v. U.S. Army Corps of Engineers, 492 F. Supp. 3d 701 (E.D. Tex. 2020).

[6] Optimus Steel, LLC v. U.S. Army Corps of Engineers, 492 F. Supp. 3d 701 (E.D. Tex. 2020).

[7] Optimus Steel, LLC v. U.S. Army Corps of Engineers, 492 F. Supp. 3d 701 (E.D. Tex. 2020), at *13.

[8] Sierra Club v. United States Army Corps of Engineers, 482 F. Supp. 3d 543 (W.D. Tex. 2020).

project.[9] A "loss" under the NWP 12 is defined by a permanent adverse effect caused by filling, flooding, excavation, or drainage.[10] Thus, the conversion of a wetland will not constitute a loss if the wetland continues to function as a wetland.[11] Further, if wetlands or waters are restored, there is similarly no loss—any loss or conversion must be permanent.[12] Under the NWP 12, a single and complete project is measured by separate and distant utility line crossings of a water body—"each crossing is considered a distinct 'single and complete project.' "[13] It is not appropriate to have a national threshold for determining "when water crossings are 'separate and distant' " because of various factors, including "topography, geology, hydrology, soils, and the characteristics of wetlands, streams, and other aquatic sources."[14] The regulations allow the Secretary to establish local guidelines for identifying "separate and distant" water crossings, and District Engineers are also able to use their own discretion to identify whether a crossing is separate and distant or whether a project proponent needs an individual permit.[15]

On April 15, 2020, a Montana District Court vacated the NWP 12, finding the Secretary failed to consult with the U.S. Fish and Wildlife Service under the ESA.[16] The court held that "substantial evidence exists that the [Secretary's] reissuance of NWP 12 may affect listed species and a critical habitat."[17] The Montana District Court eventually narrowed its remedy so that it only vacated application of the NWP 12 for new pipeline projects. The court ordered the Secretary to withhold approval of "the discharge of dredged or fill material under NWP 12 for projects constructing new oil and gas pipelines."[18] The decision was appealed to the Ninth Circuit, and a petition for certiorari was filed with the U.S. Supreme Court. The Supreme Court granted a stay of the district court's injunction for all except the part that applies to the Keystone XL pipeline, which was the subject of the original case.[19] The grant of the stay relied on a brief from the Solicitor General that argued that a broad NWP 12 injunction was not necessary because the Secretary could always demand an individual permit from the pipeline developers.[20] Since the vacatur of the Montana injunction, the NWP 12 remains active,[21] but project opponents will undoubtedly consider the Solicitor General's argument and invoke the authority to challenge project approvals and demand individual permits in the

[9]Sierra Club v. United States Army Corps of Engineers, 482 F. Supp. 3d 543 (W.D. Tex. 2020).

[10]Optimus Steel, LLC v. U.S. Army Corps of Engineers, 492 F. Supp. 3d 701 (E.D. Tex. 2020).

[11]Optimus Steel, LLC v. U.S. Army Corps of Engineers, 492 F. Supp. 3d 701 (E.D. Tex. 2020).

[12]Optimus Steel, LLC v. U.S. Army Corps of Engineers, 492 F. Supp. 3d 701 (E.D. Tex. 2020).

[13]Optimus Steel, LLC v. U.S. Army Corps of Engineers, 492 F. Supp. 3d 701 (E.D. Tex. 2020), at *12 (citing 82 Fed. Reg. 1860, 1986).

[14]Optimus Steel, LLC v. U.S. Army Corps of Engineers, 492 F. Supp. 3d 701 (E.D. Tex. 2020).

[15]Optimus Steel, LLC v. U.S. Army Corps of Engineers, 492 F. Supp. 3d 701 (E.D. Tex. 2020), at *2.

[16]Northern Plains Resource Council v. U.S. Army Corps of Engineers, 454 F. Supp. 3d 985, 993-94 (D. Mont. 2020), order amended, 460 F. Supp. 3d 1030 (D. Mont. 2020).

[17]Northern Plains Resource Council v. U.S. Army Corps of Engineers, 454 F. Supp. 3d 985, 993–94 (D. Mont. 2020), order amended, 460 F. Supp. 3d 1030 (D. Mont. 2020).

[18]Northern Plains Resource Council v. U.S. Army Corps of Engineers, 460 F. Supp. 3d 1030 (D. Mont. 2020).

[19]United States Army Corps of Engineers v. Northern Plains Resource Council, 141 S. Ct. 190, 207 L. Ed. 2d 1116 (2020).

[20]Christopher Thomas et al., *Supreme Court Revives Clean Water Act General Permit for Pipeline and Utility Line Projects* (July 14, 2020), https://www.perkinscoie.com/en/news-insights/supreme-court-revives-clean-water-act-general-permit-for-pipeline-and-utility-line-projects.html.

[21]Sierra Club v. United States Army Corps of Engineers, 482 F. Supp. 3d 543 (W.D. Tex. 2020).

future.[22]

In the waning days of the Trump administration, the Corps. issued a final rule on the Reissuance and Modification of Nationwide Permits.[23] The final rule reissued and modified 12 existing nationwide permits and issued four new nationwide permits. These NWPs went into effect on March 15, 2021.[24] The Biden Administration released a memorandum to all agencies in late January suggesting that they postpone the effective date of final rules for at least 60 days. That did not happen, and the new NWP rules are now effective.[25] The final rule removes the 300 linear foot stream impact threshold for 10 of the nationwide permits while retaining the 1/2-acre limit on loss of jurisdictional waters to satisfy the "no more than minimal adverse effects" requirements for nationwide permits.[26] The final rule also divides the previous NWP 12 into three new permits: NWP 12 for oil and gas pipelines, a new NWP 57 for the construction of electric and telecommunication utility lines, and a new NWP 58 for the construction of water and sewer lines.[27] In February, environmental groups, like the Sierra Club and Center for Biological Diversity, issued 60-day notice of intent to sue the Corps over the final NWP rules.[28]

### § 29:110 Oil Pollution Prevention (33 U.S.C.A. § 1321)

The CWA prohibits the discharge of oil or other hazardous substances into or upon the navigable waters of the United States.[1] In addition to regulating the discharge of oil or hazardous substances, the EPA has promulgated the Oil Pollution Prevention regulations under the CWA.[2] Originally published in 1973, the Oil Pollution Prevention regulations established requirements for prevention of, preparedness for, and response to, oil discharges at specific non-transportation related facilities.[3] This included an oil spill prevention and education program for small vessels, which provided for the assessment, outreach, and training and voluntary compliance activities to prevent and improve the effective response to oil spills from vessels and facilities not required to prepare a vessel response plan under CWA, such as recreational vessels, commercial fishing vessels, marinas, and aquaculture facilities.[4] The goals of these regulations were to prevent oil from reaching navigable waters, contain discharges of oil, and for facilities to implement and maintain Spill

[22] Thomas et al., *Supreme Court Revives Clean Water Act*, *supra* note 72.

[23] Reissuance and Modification of Nationwide Permits, 86 Fed. Reg. 2744 (Jan. 13, 2021).

[24] 86 Fed. Reg. 2744 (Jan. 13, 2021).

[25] William Mullen & Channing Martin, *Corps' Nationwide Permits Rule Hits Blue Wall*, JD SUPRA (Mar. 17, 2021), https://www.jdsupra.com/legalnews/corps-nationwide-permits-rule-hits-blue-5686715 (last visited June 26, 2021).

[26] William Mullen & Channing Martin, *Corps' Nationwide Permits Rule Hits Blue Wall*, JD SUPRA (Mar. 17, 2021), https://www.jdsupra.com/legalnews/corps-nationwide-permits-rule-hits-blue-5686715 (last visited June 26, 2021).

[27] William Mullen & Channing Martin, *Corps' Nationwide Permits Rule Hits Blue Wall*, JD SUPRA (Mar. 17, 2021), https://www.jdsupra.com/legalnews/corps-nationwide-permits-rule-hits-blue-5686715 (last visited June 26, 2021).

[28] William Mullen & Channing Martin, *Corps' Nationwide Permits Rule Hits Blue Wall*, JD SUPRA (Mar. 17, 2021), https://www.jdsupra.com/legalnews/corps-nationwide-permits-rule-hits-blue-5686715 (last visited June 26, 2021).

**[Section 29:110]**

[1] 33 U.S.C. § 1321(b)(1); *see also* § 13:143 of this treatise.

[2] U.S. EPA, *Clean Water Act (CWA) Compliance Monitoring*, https://www.epa.gov/compliance/clean-water-act-cwa-compliance-monitoring (last visited June 26, 2021).

[3] U.S. EPA, *Oil Pollution Act (OPA) and Federal Facilities*, https://www.epa.gov/enforcement/oil-pollution-act-opa-and-federal-facilities (last visited June 26, 2021).

[4] 33 U.S.C. § 1321(a).

Prevention, Control, and Countermeasure Plans.[5]

In 1990, the Oil Pollution Act (OPA) amended the CWA to require some oil storage facilities to prepare Facility Response Plans. These plans should detail a facility's response to a "worst-case discharge of oil."[6] Under the OPA, any person who discharges oil will be strictly liable for all resulting removal and damage costs, unless specific statutory defenses apply.[7] Facility Response Plans are required from the owners or operators of any non-transportation-related onshore facility that could "reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines[.]"[8]

The Regional Administrator will make the determination whether a facility is required to submit a response plan subject to the ensuing considerations.[9] A facility must submit a response plan if it meets any of the following criteria: (1) the facility transfers oil over water to or from vessels and has a total oil storage capacity greater than or equal to 42,000 gallons; or (2) the facility's total oil storage capacity is greater than or equal to 1 million gallons, and one of the following is true: (A) the facility does not have secondary containment for each aboveground storage area sufficiently large to contain the capacity of the largest aboveground oil storage tank within each storage area plus sufficient freeboard to allow for precipitation; (B) the facility is located at a distance where discharge could cause injury to fish and wildlife in sensitive environments; (C) the facility is located at a distance where a discharge from the facility would shut down a public drinking water intake; or (D) the facility had had a reportable oil discharge in an amount greater than or equal to 10,000 gallons within the last five years.[10] The Regional Administrator may consider: (1) frequency of past discharges; (2) proximity to navigable waters; (3) age of oil storage tanks; and (4) other facility-specific and region-specific information, including impacts on public health.[11] Any person may petition the Regional Administrator to determine whether a facility meets this criteria and should be required to submit a facility response plan.[12]

Facility Response Plans must be consistent with the National Oil and Hazardous Substance Pollution Contingency Plan and any applicable Area Contingency Plan and coordinated with the local emergency response plan.[13] EPA provides a model format and requires all plans to include, at a minimum an emergency response action plan which must contain:

(1) the identity and telephone number of a qualified individual having full authority, including contract authority, to implement removal actions;
(2) a description of information to pass to response personnel in the event of a reportable discharge;
(3) a description of the facility's response equipment and its location;
(4) a description of response capabilities, include the duties of persons at the fa-

[5] U.S. EPA, *Overview of the Spill, Prevention, Control and Countermeasure Regulation*, https://www.epa.gov/oil-spills-prevention-and-preparedness-regulations/overview-spill-prevention-control-and (last visited June 26, 2021).

[6] U.S. EPA, *Overview of the Spill, Prevention, Control and Countermeasure Regulation*, https://www.epa.gov/oil-spills-prevention-and-preparedness-regulations/overview-spill-prevention-control-and (last visited June 26, 2021); *see also* § 13:143 of this treatise.

[7] 33 U.S.C. § 2702.

[8] 40 C.F.R. § 112.20 (2021).

[9] 40 C.F.R. § 112.20(c) (2021).

[10] 40 C.F.R. § 112.20(f)(1) (2021).

[11] 40 C.F.R. § 112.20(f)(3) (2021).

[12] 40 C.F.R. § 112.20(f)(2)(iii) (2021).

[13] 40 C.F.R. § 112.20(g)(1) (2021).

cility during a response action and their response times and qualifications;
(5) plans for evacuation;
(6) a description of immediate measures to secure the source of the discharge, and to provide adequate containment and drainage of discharged oil; and a(7) a diagram of the facility.[14]

The Facility Response Plan should also include (1) facility information, and (2) information about emergency response—both of which contain descriptions almost identical to the emergency response action plan requirements. Finally, the Facility Response Plan should contain:

(1) a hazard evaluation that discuss the facility's known or reasonably identifiable discharges;
(2) response planning levels, including specific planning scenarios for a worst-case discharge, a discharge of 2,100 gallons or less, and a discharge greater than 2,100 gallons but less than 36,000 gallons (or 10% capacity of the largest tank at the facility);
(3) discharge detection systems;
(4) plan implementation;
(5) methods for self-inspection, including drills, exercises, response training, and records of inspections;
(6) safety diagrams;
(7) security systems; and
(8) a response plan cover sheet.[15]

If an owner or operator of a facility disagrees that it should be required to submit a Facility Response Plan, it may request reconsideration of the Regional Administrator's decision.[16] If reconsideration is denied, an appeal may be made to the EPA.[17]

## § 29:111 Enforcement and Penalties (33 U.S.C. § 1319)

The CWA authorizes enforcement through both government and citizen suits.[1] Oil is included in § 1321's increased fines for the discharge of oil and other hazardous substances.[2] *Oil* is defined to include "any kind in any form, including, but not limited to, petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil[.]"[3] *Discharge* includes "any spilling, leaking, pumping, pouring, emitting, emptying or dumping, but excludes discharges in compliance with a permit under § 1342[.]"[4] For the purposes of this section, the president must determine" "those quantities of oil and any hazardous substances the discharge of which may be harmful to the public health or welfare or the environment of the United States, including but not limited to fish, shellfish, wildlife, and public and private property, shorelines, and beaches."[5]

Section 1321 also provides for the establishment of a National Contingency Plan

[14] 40 C.F.R. § 112.20(h)(1) (2021).

[15] 40 C.F.R. § 112.20(h) (2021).

[16] 40 C.F.R. § 112.20(i)(1) (2021).

[17] 40 C.F.R. § 112.20(i)(3) (2021).

**[Section 29:111]**

[1] *See* §§ 13:119 to 13:131 of this treatise.

[2] Referenced in § 13:119 n.1 of this treatise.

[3] 33 U.S.C. § 1321(a)(1).

[4] 33 U.S.C. § 1321(a)(2).

[5] 33 U.S.C. § 1321(b)(4).

for an "efficient, coordinated, and effective action to minimize damage from oil and hazardous substance discharges, including containment, dispersal, and removal of oil and hazardous substances[.]"[6] Under § 1321, the owner or operator of a onshore or offshore facility is liable for actual costs of removal and any other restoration costs incurred by the federal or state government in the restoration or replacement of natural resources damaged or destroyed as a result of a discharge of oil or hazardous substance.[7] The president, or an authorized state representative, can act on behalf of the public as trustee of the natural resources to recover the costs of replacing or restoring those resources.[8]

Adjusted for inflation, Class 1 administrative penalties may not exceed $19,505 per violation, except that the maximum amount of any Class 1 administrative civil penalties shall not exceed $48,762.[9] For Class 2 penalties, the maximum is $19,505 per day for each day during which the violation continues, except that the maximum amount of any Class 2 civil penalty shall not exceed $243,808.[10] For civil penalty actions

> [a]ny person who is the owner, operator, or person in charge of any vessel, onshore facility, or offshore facility from which oil or a hazardous substance is discharged in violation [the CWA], shall be subject to a civil penalty in an amount up to [$48,762] per day of violation or an amount up to [$1,951] per barrel of oil or unit of reportable quantity of hazardous substances discharged.[11]

For violations where the person failed to properly carry out removal of the discharge or fails to comply with an order the penalty is $48,762 per day or an amount up to 3 times the costs incurred by the Oil Spill Liability Trust Fund.[12] When a person fails or refuses to comply with any regulation promulgated pursuant to the National Response System, the maximum penalty is $48,762 per day of the violation.[13] And, for any violation that was the result of gross negligence or willful misconduct, the person shall be subject to a civil penalty not less than $195,047 and not more than $5,851 per barrel of oil or unit of reportable quantity of hazardous substance discharged.[14]

## D. SAFE DRINKING WATER ACT

### § 29:112 Background Information

Before an oil and gas operator can drill a water disposal well, a steam injection well, or a carbon sequestration well, it must obtain a permit from the U.S. Environmental Protection Agency (EPA), or a state agency equivalent. The permit ensures that the applicant will meet the requirements set out in the federal Safe

[6] 33 U.S.C. § 1321(d)(2).

[7] 33 U.S.C. § 1321(f)(4).

[8] 33 U.S.C. § 1321(f)(5).

[9] 33 U.S.C. § 1321(b)(6)(B)(i) (original statutory amount $10,000 per violation with a maximum of $25,000); Civil Monetary Penalty Inflation Adjustments, 85 Fed. Reg. 83818, 83820 (Dec. 23, 2020).

[10] 33 U.S.C. § 1321(b)(6)(B)(ii) (original statutory amount $10,000 per violation with a maximum of $125,000); Civil Monetary Penalty Inflation Adjustments, 85 Fed. Reg. 83818, 83820 (Dec. 23, 2020).

[11] 33 U.S.C. § 1321(b)(7)(A) (original statutory amount $25,000 per day and $1,000 per barrel of oil); Civil Monetary Penalty Inflation Adjustments, 85 Fed. Reg. 83818, 83820 (Dec. 23, 2020).

[12] 33 U.S.C. § 1321(b)(7)(B) (original amount $25,000); Civil Monetary Penalty Inflation Adjustments, 85 Fed. Reg. 83818, 83820 (Dec. 23, 2020).

[13] 33 U.S.C. § 1321(b)(7)(C) (original amount $25,000); Civil Monetary Penalty Inflation Adjustments, 85 Fed. Reg. 83818, 83820 (Dec. 23, 2020).

[14] 33 U.S.C. § 1321(b)(7)(D) (original amounts $100,000 and $3,000); Civil Monetary Penalty Inflation Adjustments, 85 Fed. Reg. 83818, 83820 (Dec. 23, 2020).

Drinking Water Act (SDWA).[1] The SDWA was originally passed by the United States Congress in 1974 and was subsequently amended in 1986 and 1996. The SDWA is intended to protect the nation's drinking water and sources of drinking water, including rivers, lakes, reservoirs, springs, and certain groundwater supply wells. Under the SDWA, the EPA sets health-based standards for drinking water quality to protect against both naturally occurring and manmade contaminants, and monitors states, local authorities, and water suppliers who enforce those standards.[2]

## § 29:113 Enforcement Responsibility and Implementation

The SDWA is implemented and enforced by the EPA, but the EPA can delegate enforcement responsibility to the states when a state's program meets certain criteria.[1] This is called primary enforcement responsibility, or primacy. A state has primary enforcement responsibility for public water systems when the EPA determines that the state has: (1) adopted drinking water regulations that are no less stringent than the national primary drinking water regulations promulgated by the EPA; (2) adopted and is implementing adequate procedures for the enforcement of such state regulations;[2] (3) established and will maintain record keeping and reporting of its activities; (4) established adequate variance procedures as stringent as the federal procedures; (5) the authority to assess administrative penalties; (6) adopted and can implement an adequate plan for the provision of safe drinking water under emergency circumstances; and (6) adequate electronic records regulations.[3]

## § 29:114 Procedures/Process for State Delegation

A state may apply to the EPA for a determination that the state has primary enforcement responsibility for public water systems in the state pursuant to § 1413 of the SDWA.[1] The SDWA regulations specify that the application should be as concise as possible and include a side-by-side comparison of the federal requirements and the corresponding state authorities, including citations to specific statutes and administrative regulations or ordinances, and judicial decisions where appropriate, which demonstrate adequate authority to meet the requirements of § 142.10, described above.[2] State applications for primary enforcement responsibility must include, among other information, the text of the state's primary drinking water

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**[Section 29:112]**

[1] 42 U.S.C. §§ 300f, et seq.

[2] 42 U.S.C. § 300g-1.

**[Section 29:113]**

[1] 42 U.S.C. § 300g-1; 42 U.S.C. § 300g-2.

[2] These procedures include maintenance of an inventory of public water systems, a systematic program for conducting sanitary surveys of public water systems in the state, the establishment and maintenance of a state program for the certification of laboratories conducting analytical measurements of drinking water contaminants, assurance of the availability to the state of laboratory facilities certified by the EPA and capable of performing analytical measurements of all contaminants specified in the state primary drinking water regulations, the establishment and maintenance of an activity to assure that the design and construction of new or substantially modified public water system facilities will be capable of compliance with the state primary drinking water regulations, and statutory or regulatory enforcement authority adequate to compel compliance with the state primary drinking water regulations. 40 C.F.R. § 142.10 (2021).

[3] 40 C.F.R. § 142.10 (2021).

**[Section 29:114]**

[1] 40 C.F.R. § 142.11 (2021).

[2] 40 C.F.R. § 142.11 (2021).

regulations and a description of the state's enforcement procedures.[3] The EPA must act on an application for primary enforcement responsibility within 90 days after receiving such application.[4] Once a state's program has been approved, in order to retain primary enforcement responsibility, states must adopt all new and revised national primary drinking water regulations promulgated under the SDWA.[5]

## § 29:115 Underground Injection Control Program

Of particular interest to the oil and gas industry and its permitting needs for oil and gas operations is Part C of the SDWA. Part C is intended to ensure protection of underground sources of drinking water against contamination by underground injection (steam flooding, produced water re-injection, $CO_2$ injection, and the like in the context of oil and gas operations) and directs the establishment of statewide programs to control underground injections.[1] All state underground injection control (UIC) programs must prohibit "any underground injection in such State which is not authorized by a permit," and require permit applicants to demonstrate that "the underground injection will not endanger drinking water sources."[2] The EPA's regulations define an "underground source of drinking water" as an aquifer, or a portion thereof, which (1) supplies any public water system, or (2) contains a sufficient quantity of groundwater to supply a public water system, and currently supplies drinking water for human consumption, or contains fewer than 10,000 mg/l total dissolved solids; and is not an exempted aquifer.[3] This means that oil and gas operators must obtain a UIC permit from either the EPA, or the state if primacy has been granted, before drilling disposal wells, enhanced recovery wells, or hydrocarbon storage wells.

A state's UIC program may be administered by the EPA, or the state may apply to the EPA for primary enforcement responsibility for the program by demonstrating that its UIC program meets the requirements set forth in the EPA's regulations.[4] The EPA has approved UIC primacy programs for Class I, II, III, IV, and V wells in 33 states, for Class II wells in just eight states and two tribal reservations, and for all well classes in just two states.[5]

## § 29:116 UIC Well Classes

There are six different classes of injection wells.[1] Class I wells are industrial and municipal waste disposal wells and are used to inject hazardous and non-hazardous wastes into deep, confined rock formations. Class II wells are oil- and gas-related injection wells and are used only to inject fluids associated with oil and natural gas production. Class II fluids are primarily brines that are brought to the surface dur-

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[3] 40 C.F.R. § 142.11 (2021).

[4] 40 C.F.R. § 142.11(b)(1) (2021).

[5] 40 C.F.R. § 142.12(a) (2021).

**[Section 29:115]**

[1] Center for Biological Diversity v. Department of Conservation, 26 Cal. App. 5th 161, 166, 236 Cal. Rptr. 3d 729 (1st Dist. 2018); 42 U.S.C § 300h-1.

[2] 42 U.S.C. §§ 300h(b)(1)(A) to (B), 300h-4(a).

[3] 40 C.F.R. § 144.3 (2021). "Exempted aquifers" are discussed below.

[4] 42 U.S.C. § 300h-1(b), (c).

[5] U.S. EPA, *Underground Injection Control (UIC), Primary Enforcement Authority for the Underground Injection Control Program*, https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program (last visited June 26, 2021).

**[Section 29:116]**

[1] 40 C.F.R. § 144.6 (2021).

ing oil and gas production. Class III wells are injection wells for solution mining and are used to inject fluids to dissolve and extract minerals. Class IV wells are shallow hazardous and radioactive injection wells and are used to dispose of hazardous or radioactive wastes into or above a geologic formation that contains an underground source of drinking water.[2] Class V wells are for the injection of non-hazardous fluids underground, usually into or above underground sources of drinking water. Class VI wells are used for geologic sequestration of carbon dioxide.

### § 29:117 Focus on Class II Wells

As described above, Class II wells are used only to inject fluids associated with oil and gas production. There are three categories of Class II wells: (1) disposal wells; (2) enhanced recovery wells; and (3) hydrocarbon storage wells.[1]

### § 29:118 UIC Permitting

Oil and gas operators cannot conduct any injection activity in a manner that allows for the movement of fluid containing any contaminant into underground sources of drinking water if the contaminant will violate a primary drinking water regulation or adversely affect people's health.[1] All underground injections must be authorized either by rule or by permit.[2] Permit applications for Class II wells must contain the information listed in 40 C.F.R. § 144.31(e), which includes information regarding the proposed injection activities, facility and operator information, a list of all permit approvals required for the project, and a topographic map.

### § 29:119 Aquifer Exemptions

Another important aspect of the SDWA as applied to oil and gas operations is the ability of the EPA to find an underground groundwater aquifer that is exempt from the SDWA's strictures. Aquifer exemptions allow certain underground sources of water to be used for oil or mineral extraction or disposal purposes in compliance with the EPA's UIC requirements.[1] UIC permit applicants can seek an aquifer exemption by submitting an application package to the primary agency. If a state has been granted primacy, the state reviews the applicant's submittal. If the information submitted supports a determination that the proposed aquifer exemption meets federal regulatory criteria contained in 40 C.F.R. § 146.4, the state proposes to exempt the aquifer, provides an opportunity for public participation and comment, and submits a request for approval of the exemption to the EPA.[2] No designation of an exempted aquifer is final until approved by the EPA Administrator as

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[2] 40 C.F.R. § 144.6 (2021); The EPA banned the use of Class IV injection wells in 1984, and these wells may only operate as part of an authorized groundwater cleanup action.

**[Section 29:117]**

[1] U.S. EPA, *Underground Injection Control (UIC), Class II Oil and Gas Related Injection Wells*, https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells (last visited June 26, 2021).

**[Section 29:118]**

[1] 40 C.F.R. § 144.12 (2021).

[2] 40 C.F.R. § 144.11 (2021).

**[Section 29:119]**

[1] U.S. EPA, *Underground Injection Control (UIC), Aquifer Exemptions in the Underground Injection Control Program*, https://www.epa.gov/uic/aquifer-exemptions-underground-injection-control-program (last visited June 26, 2021).

[2] U.S. EPA, *EPA Oversight of California's Underground Injection Control (UIC) Program*, https://www.epa.gov/uic/epa-oversight-californias-underground-injection-control-uic-program (last visited June 26, 2021).

part of an approved UIC program.

As stated above, in order for the EPA to approve an aquifer exemption, it must follow the regulatory criteria laid out in 40 C.F.R. § 146.4. The EPA must find that the state, or the applicant if the state does not have primacy, has shown that the aquifer proposed for exemption does not currently serve as a source of drinking water.[3] Next, the EPA must find that the aquifer cannot now, and will not in the future, serve as a source of drinking water, or that the total dissolved solids content of the groundwater is more than 3,000 and less than 10,000 mg/l and it is not reasonably expected to supply a public water system.[4]

## E. COMPREHENSIVE ENVIRONMENTAL RESPONSE, COMPENSATION, AND LIABILITY ACT

### § 29:120 Overview

On December 11, 1980, Congress passed the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA).[1] It was prompted by environmental disasters such as the one that occurred at Love Canal and operates as a companion law to the Resource Conservation and Recovery Act (RCRA), although its purpose is different.[2] While RCRA provides cradle to grave regulation, CERCLA was designed to allow a federal response to releases, past releases, or threatened releases of hazardous substances that could endanger public health or the environment.[3]

CERCLA has two fundamental goals: the first is to clean up hazardous substances that are released into the environment, and the second is to hold responsible parties liable for the costs of these clean-ups.[4] As a general matter, "[t]o state a prima facie case under CERCLA, 42 U.S.C. § 9607(a), a plaintiff must allege that:

(1) the waste disposal site is a 'facility' within the meaning of 42 U.S.C. § 9601(9);
(2) a 'release' or 'threatened release' of a 'hazardous substance' from the facility has occurred, *id*. § 9607(a)(4);
(3) such release or 'threatened release' will require the expenditure of response costs that are 'consistent with the national contingency plan,' *id*. §§ 9607(a)(4) and (a)(4)(B); and,
(4) the defendant falls within one of four classes of persons subject to CERCLA's liability provisions."[5]

The following four categories of parties may be held liable under CERCLA (often called Potentially Responsible Parties or PRPs):

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[3] 40 C.F.R. § 146.4 (2021).

[4] 40 C.F.R. § 146.4 (2021).

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[1] 42 U.S.C. §§ 9601 to 9675; *See* U.S. EPA, *Superfund: CERCLA Overview*, https://www.epa.gov/superfund/superfund-cercla-overview (last visited June 24, 2021). CERCLA was then amended by the Superfund Amendments and Reauthorization Act (SARA) on October 17, 1986. Pub. L. No. 99-499.

[2] *See* U.S. EPA, *What is Superfund?*, https://www.epa.gov/superfund/what-superfund (last visited June 24, 2021).

[3] *See What is Superfund?*, note 1. "Environment" is defined, in relevant part, as "any other surface water, ground water, drinking water supply, land surface or subsurface strata, or ambient air within the United States or under the jurisdiction of the United States." 42 U.S.C. § 9601(8).

[4] *See* Price Trucking Corp. v. Norampac Industries, Inc., 748 F.3d 75, 79, 78 Env't. Rep. Cas. (BNA) 1133 (2d Cir. 2014) ("CERCLA's primary purposes are axiomatic: (1) to encourage the timely cleanup of hazardous waste sites; and (2) to place the cost of that cleanup on those responsible for creating or maintaining the hazardous condition.") (citation omitted).

[5] Cose v. Getty Oil Co., 4 F.3d 700, 703–04, 37 Env't. Rep. Cas. (BNA) 1153, 23 Envtl. L. Rep. 21335, 129 O.G.R. 583 (9th Cir. 1993), as amended, (Oct. 1, 1993).

(1) Present owners and operators of facilities;
(2) Those who, at the time of disposal of the hazardous substances, owned or operated facilities;[6]
(3) Those who arranged for transport of hazardous substances for disposal or treatment;[7] and
(4) Certain transporters of hazardous substances.[8]

Unless a statutory defense or exclusion (including the petroleum exclusion) applies, covered parties are liable for "all costs of removal or remedial action incurred by the United States Government or a State . . . not inconsistent with the national contingency plan[,]" and "any other necessary costs of response incurred by any other person consistent with the national contingency plan[.]"[9]

## § 29:121 The Petroleum Exclusion

While CERCLA is discussed in detail elsewhere in this treatise, particular aspects are relevant to the oil and gas industry.

CERCLA provides that a "hazardous substance"[1] does not include:

- "petroleum, including crude oil or any fraction thereof which is not otherwise specifically listed or designated as a hazardous substance";[2]
- "and the term does not include natural gas, natural gas liquids, liquefied nat-

[6]The Supreme Court held that, under CERCLA, "an operator must manage, direct, or conduct operations specifically related to pollution, that is, operations having to do with the leakage or disposal of hazardous waste, or decisions about compliance with environmental regulations." U.S. v. Bestfoods, 524 U.S. 51, 66–67, 118 S. Ct. 1876, 141 L. Ed. 2d 43, 46 Env't. Rep. Cas. (BNA) 1673, 28 Envtl. L. Rep. 21225, 157 A.L.R. Fed. 735 (1998).

[7]An arranger is defined as "any person who by contract, agreement, or otherwise arranged for disposal or treatment . . . of hazardous substances owned or possessed by such person, by any other party or entity, at any facility . . . owned or operated by another party or entity and containing such hazardous substances[.]" 42 U.S.C. § 9607(a)(3).

[8]42 U.S.C. § 9607(a)(4).

[9]42 U.S.C. § 9607(a)(4)(A) to (B). CERCLA § 113, added in 1986 as part of SARA, contains a subsection entitled "Contribution." This subsection states: "Any person may seek contribution from any other person who is liable or potentially liable under [§ 107(a)], during or following any civil action under [§§ 106 or 107(a)] . . . . In resolving contribution claims, the court may allocate response costs among liable parties using such equitable factors as the court determines are appropriate. Nothing in this subsection shall diminish the right of any person to bring an action for contribution in the absence of a civil action under [§§ 106 or 107]." 42 U.S.C. § 9613(f)(1). Under § 113, a party that "has resolved its liability to the United States or a State in an administrative or judicially approved settlement" is immune from contribution claims made by other Potentially Responsible Parties "regarding matters addressed in the settlement." 42 U.S.C. § 9613(f)(2). *[See* § 14:143 of this treatise.

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[1]The term "hazardous substance" means:

> (A) any substance designated pursuant to section 311(b)(2)(A) of the Federal Water Pollution Control Act . . ., (B) any element, compound, mixture, solution, or substance designated pursuant to section 9602 of this title, (C) any hazardous waste having the characteristics identified under or listed pursuant to section 3001 of the Solid Waste Disposal Act . . . (but not including any waste the regulation of which under the Solid Waste Disposal Act . . . has been suspended by Act of Congress), (D) any toxic pollutant listed under section 307(a) of the Federal Water Pollution Control Act . . ., (E) any hazardous air pollutant listed under section 112 of the Clean Air Act . . ., and (F) any imminently hazardous chemical substance or mixture with respect to which the Administrator has taken action pursuant to section 7 of the Toxic Substances Control Act . . . . The term does not include petroleum, including crude oil or any fraction thereof which is not otherwise specifically listed or designated as a hazardous substance under subparagraphs (A) through (F) of this paragraph, and the term does not include natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel (or mixtures of natural gas and such synthetic gas).

42 U.S.C. § 9601(14).

[2]42 U.S.C. § 9601(14).

ural gas, or synthetic gas usable for fuel (or mixtures of natural gas and such synthetic gas)."[3]

This is known as the "petroleum exclusion." Courts have found that "the primary purpose of the exclusion for petroleum, which is defined principally in terms of crude oil and crude oil fractions, was to exclude from CERCLA's coverage 'spills or other releases strictly of oil,' S. Rep. No. 96-848, 96th Cong., 2d Sess. 29 to 30 (1980), not releases of hazardous substances mixed with oil."[4]

Courts note that "CERCLA has acquired a well-deserved notoriety for vaguely-drafted provisions and an indefinite, if not contradictory, legislative history."[5] While the exact intent behind the exclusion is unclear from an examination of the hastily-drafted statute and its history, one potential basis for the exclusion is the fact that petroleum is covered by other statutes. These include the Oil Pollution Act of 1990 (P.L. 101-380), passed after the Exxon Valdez oil spill and decades of debate over a comprehensive law governing oil spills.

In analyzing the limits of the exclusion, the EPA took the position in a 1987 memo that when petroleum is mixed with hazardous substance(s) before it is released into the environment, the entire mixture should be considered hazardous under CERCLA.[6] This allows the EPA to respond to releases of hazardous substances that occur together with petroleum releases.

The outlines of this exclusion have been litigated in a number of cases.[7] However, the practical effect of the exclusion has been to exclude CERCLA itself as a favorable statute for petroleum cleanups in many cases.

## § 29:122 Excluded as a "Hazardous Substance."

One of the early cases analyzing the petroleum exclusion, *Wilshire Westwood Associates*, held that "the application of the standards governing statutory construction to the words of the petroleum exclusion requires us to exclude gasoline, even leaded gasoline, from the term 'hazardous substance' for purposes of CERCLA."[1] The effect of this is to apply the petroleum exclusion to unrefined and refined gasoline, despite the fact that "certain of its indigenous components and certain addi-

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[3] 42 U.S.C. § 9601(14); "Mineral spirits that are distilled from petroleum are considered petroleum for the purpose of CERCLA Section 101(14) and, therefore, are excluded from the definition of hazardous substance." U.S. EPA, *Mineral Spirits Excluded From the CERCLA?*, https://www.epa.gov/epcra/mineral-spirits-excluded-cercla (last visited June 24, 2021).

[4] City of New York v. Exxon Corp., 744 F. Supp. 474, 490, 31 Env't. Rep. Cas. (BNA) 1963, 21 Envtl. L. Rep. 20248 (S.D. N.Y. 1990), adhered to on reconsideration, 766 F. Supp. 177, 34 Env't. Rep. Cas. (BNA) 1623, 22 Envtl. L. Rep. 20145 (S.D. N.Y. 1991).

[5] U.S. v. Mottolo, 605 F. Supp. 898, 902, 22 Env't. Rep. Cas. (BNA) 1529, 15 Envtl. L. Rep. 20444 (D.N.H. 1985).

[6] *See* U.S. EPA, Office of General Counsel, *Scope of the CERCLA Petroleum Exclusion Under Sections 101(14) and 104(a)(2)* (July 31, 1987), https://www.epa.gov/sites/production/files/2013-09/documents/petro-exclu-mem.pdf; *see also* Franklin County Convention Facilities Authority v. American Premier Underwriters, Inc., 240 F.3d 534, 541, 51 Env't. Rep. Cas. (BNA) 2125, 31 Envtl. L. Rep. 20470, 2001 FED App. 0041P (6th Cir. 2001) ("[P]etroleum products mixed with hazardous substances [that are] not constituent elements of petroleum are hazardous substances.").

[7] Disputes over the categorization of the chemicals may preclude summary judgment. *See* U.S. v. Poly-Carb, Inc., 951 F. Supp. 1518, 1528, 44 Env't. Rep. Cas. (BNA) 1306, 27 Envtl. L. Rep. 20902 (D. Nev. 1996) ("[I]f we cannot say what was in those tanks, we likewise cannot say whether it was 'spent,' a 'by-product,' a 'feedstock,' or 'being reclaimed.' Summary judgment is not appropriate.").

**[Section 29:122]**

[1] Wilshire Westwood Associates v. Atlantic Richfield Corp., 881 F.2d 801, 804, 30 Env't. Rep. Cas. (BNA) 1065, 19 Envtl. L. Rep. 21313 (9th Cir. 1989); *see* Kuneman v. Redwood Oil Co., 32 Fed. Appx. 962, 963 (9th Cir. 2002) ("petroleum exclusion applies to refined and unrefined gasoline").

tives during the refining process have themselves been designated as hazardous substances within the meaning of CERCLA."[2]

The *Wilshire Westwood* principle that indigenous compounds which are, by themselves, hazardous substances, but when combined with petroleum in the refining process trigger the petroleum exclusion, has been applied under numerous circumstances.[3] As one court succinctly put it, "whether the petroleum exclusion applies depends both on *what* is spilled and on *how* it is spilled," noting that lead in spilled gasoline would be excluded under CERCLA, while lead in the form of abandoned lead acid batteries would not.[4]

Similarly, a plume of a hazardous substance, such as benzene, that effectively separates from and migrates away from an oil spill will likely still be subject to the exclusion.[5] A self-evident extension of the principle is that the addition to petroleum of substances or compounds that are *not* themselves deemed "hazardous," such as spacer fluid and drilling mud, will not vitiate application of the exclusion.[6]

Under a liberal application of the exclusion, the mere presence of particular hazardous substances, such as benzene, ethylbenzene, toluene, xylene, and lead, can lead a court to the "inescapable conclusion" that those hazardous substances were derived from petroleum products onsite, resulting in dismissal of a CERCLA lawsuit.[7] Moreover, even if concentrations of hazardous substances are above those normally found in unused petroleum, a court may still apply the petroleum exclusion if the evidence indicates that those higher concentrations are due to natural volatilization and biodegradation of petroleum over time.[8]

Some courts have also held that "used petroleum products are covered by the petroleum exclusion," as long as "CERCLA-listed hazardous substances have not been added to the petroleum product during its use, nor have the concentrations of CERCLA-listed hazardous substances in the petroleum product been increased by its use."[9] At least one court has ruled that even an allegedly intentional "spill" of a refined petroleum product was exempt from CERCLA's purview.[10] The EPA's "rules and regulations also provide that the petroleum exclusion applies to crude oil, petroleum feedstocks, and refined petroleum products."[11]

## § 29:123 Included as a "Hazardous Substance."

[2]Wilshire Westwood, 881 F.2d at 810; *see* Gardner v. Chevron Capital Corporation, 715 Fed. Appx. 737 (9th Cir. 2018); Petrovic v. Amoco Oil Co., 200 F.3d 1140, 1154, 49 Env't. Rep. Cas. (BNA) 1972, 45 Fed. R. Serv. 3d 948, 30 Envtl. L. Rep. 20259 (8th Cir. 1999); Foster v. U.S., 922 F. Supp. 642, 659, 42 Env't. Rep. Cas. (BNA) 1775, 26 Envtl. L. Rep. 21327 (D.D.C. 1996) ("because the plaintiff fails to demonstrate that the PAHs, TPHs, and kerosene present at the Site fall outside of the CERCLA's exception for petroleum products, no CERCLA liability may attach for contamination related to such").

[3]*Poly-Carb, Inc.*, 951 F. Supp. at 1526.

[4]*Poly-Carb, Inc.*, 951 F. Supp. at 1526.

[5]White Plains Housing Authority v. Getty Properties Corp., 80 Env't. Rep. Cas. (BNA) 1163, 2014 WL 7183991, at *9 (S.D. N.Y. 2014).

[6]In re Oil Spill by the Oil Rig Deepwater Horizon in the Gulf of Mexico, on April 20, 2010, 81 Env't. Rep. Cas. (BNA) 1867, 2015 WL 5363039, at *6 (E.D. La. 2015).

[7]Bunger v. Hartman, 797 F. Supp. 968, 972, 36 Env't. Rep. Cas. (BNA) 1496, 23 Envtl. L. Rep. 20255 (S.D. Fla. 1992).

[8]Organic Chemical Site PRP Group v. Total Petroleum Inc., 58 F. Supp. 2d 755, 763 (W.D. Mich. 1999).

[9]Southern Pacific Transp. Co. v. California (Caltrans), 790 F. Supp. 983, 986, 34 Env't. Rep. Cas. (BNA) 1188, 22 Envtl. L. Rep. 20351 (C.D. Cal. 1991).

[10]*Foster*, 922 F. Supp. at 652 (finding no CERCLA liability where a defendant "sprayed" kerosene onto the facility).

[11]In re Oil Spill by the Oil Rig Deepwater Horizon in the Gulf of Mexico, on April 20, 2010, 81 Env't. Rep. Cas. (BNA) 1867, 2015 WL 5363039, at *5 (E.D. La. 2015).

Many courts, and the EPA itself,[1] have concluded that, while "Congress intended to exclude oil spills from the coverage of CERCLA," it "did not intend to exclude waste oils . . . which are by no means strictly 'crude oil or any fraction thereof.' "[2] Courts have regularly applied the distinction between excluded crude oil or refined petroleum and non-excluded used or waste oils, and have held that used motor oil, emulsions containing used oil, and used oil sludge are all subject to CERCLA.[3]

Additional caselaw further refined this basic principle: for example, in *Cose v. Getty Oil*, the Ninth Circuit held that "crude oil tank bottoms are not 'petroleum, including crude oil or a fraction thereof' under CERCLA and therefore do not fall within CERCLA's petroleum exclusion in the first instance."[4] Crucial to the court's holding was the fact that "crude oil tank bottoms are never 'subjected to various refining processes' . . . [or] used 'for producing useful products,' " and therefore are not "petroleum" under the Ninth Circuit's definition announced in *Wilshire Westwood*.[5]

As an elaboration of *Wilshire Westwood* and its progeny, when hazardous substances are added to waste oil, resulting in larger amounts of hazardous components than would occur in crude or refined petroleum products, the exemption does not apply.[6] Even a *de minimis* amount of additional hazardous substances can lead to CERCLA liability,[7] and the fact that the addition was unintentional does not save the defendant from liability.[8] Likewise, hazardous substances that have "commingled with the petroleum products in the soil and [are] floating on the groundwater" have also been held to render the CERCLA petroleum exclusion inapplicable.[9]

The EPA has distinguished between "oil that naturally contains low levels of haz-

**[Section 29:123]**

[1]Notification Requirements; Reportable Quantity Adjustments, 50 Fed. Reg. 13456, 13460 (Apr. 4, 1985) (to be codified at 40 C.F.R. §§ 117, 302 (2021)).

[2]*City of New York*, 744 F. Supp. at 490. In cases involving waste oils or other used petroleum products, courts may accept circumstantial evidence and conclude that oil contains non-excluded hazardous substances; this then places the burden on the defendant claiming the petroleum exclusion to show that the deposited oil did not contain contaminants. *See* Members of Beede Site Group v. Federal Home Loan, Mortg. Corp., 968 F. Supp. 2d 455, 461, 77 Env't. Rep. Cas. (BNA) 1811 (D.N.H. 2013).

[3]Ekotek Site PRP Committee v. Self, 932 F. Supp. 1319, 1327 (D. Utah 1996); U.S. v. Alcan Aluminum Corp., 964 F.2d 252, 266–67, 35 Env't. Rep. Cas. (BNA) 1073, 22 Envtl. L. Rep. 21124 (3d Cir. 1992); U.S. v. Western Processing Co., Inc., 761 F. Supp. 713, 722, 32 Env't. Rep. Cas. (BNA) 2029, 21 Envtl. L. Rep. 20976 (W.D. Wash. 1991).

[4]Cose v. Getty Oil Co., 4 F.3d 700, 708, 37 Env't. Rep. Cas. (BNA) 1153, 23 Envtl. L. Rep. 21335, 129 O.G.R. 583 (9th Cir. 1993), as amended, (Oct. 1, 1993) (emphasis omitted); *see W. Processing Co.*, 761 F. Supp. at 724 ("drums of tank bottom sludge generated by GATX is a waste material contaminated with PAHs and, additionally, in some instances, with lead, and is not a 'fraction of petroleum' exempted from coverage under CERCLA").

[5]*Cose*, 4 F.3d at 705.

[6]State of Wash. v. Time Oil Co., 687 F. Supp. 529, 532, 27 Env't. Rep. Cas. (BNA) 2076, 18 Envtl. L. Rep. 21376 (W.D. Wash. 1988); *see also* Darbouze v. Chevron Corp., 47 Env't. Rep. Cas. (BNA) 1480, 1998 WL 512941, at *5 (E.D. Pa. 1998) (if a hazardous substance "is at a level exceeding what is normally found in petroleum, or if the 'hazardous substance' is not normally found in petroleum, then the 'petroleum exclusion' does not apply"); USOR Site PRP Group v. LEI Rone Engineers, Ltd, 85 Env't. Rep. Cas. (BNA) 1183, 2017 WL 2840018, at *4 (S.D. Tex. 2017) (in a cost-recovery action for the remediation of a former oil processing and waste treatment facility, the court rejected application of the petroleum exclusion to an oily discharge that has been infused with hazardous substances, determining the "fuel discharged was introduced into a petroleum product used in machines that allowed for the transfer of heavy metals into the water").

[7]*Members of the Beede Site Grp.*, 968 F. Supp. 2d at 460.

[8]*City of New York*, 766 F. Supp. at 187.

[9]Tosco Corp. v. Koch Industries, Inc., 216 F.3d 886, 893, 30 Envtl. L. Rep. 20647 (10th Cir. 2000).

ardous substances and oil to which hazardous substances have been added through use."[10] While the EPA has "extended the petroleum exclusion to the former category of oily substances, it has specifically declined to extend such protection to the latter category."[11] Some courts have held that this interpretation of the petroleum exclusion comports with the relevant legislative history, which indicates that the "exclusion was intended for oil spills, not for releases of oil which has become infused with hazardous substances through use."[12]

## § 29:124 Reportable Quantity Reporting

Despite the petroleum exclusion, some oils are regulated under CERCLA because they are specifically listed. For example, "40 CFR 302.4, Table 302.4 specifically lists a number of waste oils (e.g., F010, and K048 through K052)" and their Reportable Quantities ("RQs").[1] If those chemicals are released in quantities equal to or greater than their RQs, the release is required to be reported.[2]

CERCLA requires the reporting of releases of a hazardous substance into the environment in an amount that exceeds a reportable quantity within a 24-hour period.[3] Section 101(22) defines "release" as any "spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping, or disposing into the environment (including the abandonment or discarding of barrels, containers, and other closed receptacles containing any hazardous substance or pollutant or contaminant)." Further, the term "hazardous substance" is defined in § 101(14) by reference to the Clean Water Act, the Clean Air Act, the Resource Conservation and Recovery Act, and the Toxic Substances Control Act.

RQs can initially be provisionally set by Congress.[4] After further evaluation and notice and comment, the EPA can then further adjust them in order to protect public health and the environment from the hazard.[5] The EPA employs a two-step process: the first step evaluates the "intrinsic physical, chemical, and toxicological properties of each substance" and the second step evaluates the substance's "susceptibility to certain degradative processes."[6]

CERCLA provides exemptions from the notification requirement in limited circumstances. Section 103(f) exempts reporting for "any release of a hazardous substance . . . which is a continuous release, stable in quantity and rate and is . . . a release of which notification has been given [pursuant to reporting requirements]

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[10] In re LandSource Communities Development LLC, 485 B.R. 310, 321 (Bankr. D. Del. 2013) (citation omitted).

[11] In re LandSource Communities Development LLC, 485 B.R. 310, 321 (Bankr. D. Del. 2013).

[12] In re LandSource Communities Development LLC, 485 B.R. 310, 321 (Bankr. D. Del. 2013).

**[Section 29:124]**

[1] U.S. EPA, *Specific Substances Excluded Under CERCLA Petroleum Exclusion*, https://www.epa.gov/epcra/specific-substances-excluded-under-cercla-petroleum-exclusion (last visited June. 25, 2021). The EPA has either established or proposed adjustments to the RQs for all of the roughly 800 Superfund substances. U.S. EPA, *CERCLA and EPCRA Continuous Release Reporting*, https://www.epa.gov/epcra/cercla-and-epcra-continuous-release-reporting (last visited June 25, 2021).

[2] *Specific Substances Excluded Under CERCLA Petroleum Exclusion*, *supra* note 40.

[3] 42 U.S.C. § 9603(a); Notification Requirements; Reportable Quantity Adjustments, 50 Fed. Reg. 13456, 13460 (Apr. 4, 1985) (to be codified at 40 C.F.R. §§ 117, 302 (2021)).

[4] Note that the Clean Water Act and CERCLA RQs are the same. Notification Requirements; Reportable Quantity Adjustments, 50 Fed. Reg. at 13473 (Apr. 4, 1985).

[5] *See* U.S. EPA, *Reportable Quantity (RQ) Adjustment Methodology*, https://www.epa.gov/epcra/reportable-quantity-rq-adjustment-methodology (last visited June. 25, 2021).

[6] *See* U.S. EPA, *Reportable Quantity (RQ) Adjustment Methodology*, https://www.epa.gov/epcra/reportable-quantity-rq-adjustment-methodology (last visited June. 25, 2021).

for a period sufficient to establish the continuity, quantity, and regularity of such release."[7] This provision addresses releases from sources that are "routine, anticipated, and intermittent and incidental to normal operations or treatment processes."[8]

## § 29:125 Federally permitted releases

CERCLA requires that any release of a hazardous substance in excess of the reportable quantity of the substance be reported; there is an exception when the release is a federally permitted release, defined by reference to various environmental statutes.[1] For that category of releases, 42 U.S.C. § 9607(j) states that "[r]ecovery by any person (including the United States . . .) for response costs or damages resulting from a federally permitted release shall be pursuant to existing law in lieu of this section."

Typically, the emissions in question are required to comply with the relevant permits in order to be exempt from the reporting requirements.[2] However, in the recent *Clean Air Council* case, which involved the releases of hydrogen sulfide, benzene, and other hazardous components, the court was asked to determine whether "emissions from a facility that holds Clean Air Act [CAA] permits are exempt from CERCLA's reporting requirements, regardless of whether the emissions comply with those permits."[3] There, the court concluded that "the phrase 'subject to,' as used in § 9601(10) of CERCLA, is unambiguous and does not require that the air emissions comply with a Clean Air Act permit in order to be exempt."[4] In the court's opinion, the phrase "[s]ubject to" means only that the "responsible facility must abide by the requirements of that permit," in addition to the requirements of the CAA and the reporting requirements of that law, "rather than the reporting requirements of CERCLA."[5] This court's interpretation was unusually broad, and the case has been appealed as of the date of this publication.

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[7] Such continued releases are governed by 40 C.F.R. § 302.8 (2021).

[8] 40 C.F.R. § 302.8(b) (2021). According to the EPA's CERCLA and EPCRA Continuous Release Reporting guidance, located at https://www.epa.gov/epcra/cercla-and-epcra-continuous-release-reporting, releases that may qualify as continuous releases include those that:

- "Are normal plant operation or treatment processes;
- Are stable in quantity and rate; and either
- Occur without interruption of abatement, or
- Are routine, anticipated and intermittent."

**[Section 29:125]**

[1] "Congress defined the term 'federally permitted release' in relation to other environmental protection laws: the Clean Water Act (which includes the Federal Water Pollution Control Act); the Solid Waste Disposal Act; the Marine Protection, Research, and Sanctuaries Act of 1972; the Safe Drinking Water Act; the Clean Air Act; the Atomic Energy Act of 1954; and state laws related to crude oil and natural gas. 42 U.S.C. § 9601(10)." Clean Air Council v. United States Steel Corporation, 2020 WL 2490023, at *2 (W.D. Pa. 2020), aff'd, 2 F.4th 112 (3d Cir. 2021), on reh'g, 4 F.4th 204 (3d Cir. 2021) and reh'g granted, judgment vacated, 3 F.4th 605 (3d Cir. 2021) and aff'd, 4 F.4th 204 (3d Cir. 2021).

[2] *See, e.g.*, U.S. v. Washington State Dept. of Transp., 716 F. Supp. 2d 1009, 1016, 72 Env't. Rep. Cas. (BNA) 1506 (W.D. Wash. 2010).

[3] Clean Air Council v. United States Steel Corporation, 2020 WL 2490023, at *2 (W.D. Pa. 2020), aff'd, 2 F.4th 112 (3d Cir. 2021), on reh'g, 4 F.4th 204 (3d Cir. 2021) and reh'g granted, judgment vacated, 3 F.4th 605 (3d Cir. 2021) and aff'd, 4 F.4th 204 (3d Cir. 2021).

[4] Clean Air Council v. United States Steel Corporation, 2020 WL 2490023, at *4 (W.D. Pa. 2020), aff'd, 2 F.4th 112 (3d Cir. 2021), on reh'g, 4 F.4th 204 (3d Cir. 2021) and reh'g granted, judgment vacated, 3 F.4th 605 (3d Cir. 2021) and aff'd, 4 F.4th 204 (3d Cir. 2021).

[5] Clean Air Council v. United States Steel Corporation, 2020 WL 2490023, at *4 (W.D. Pa. 2020), aff'd, 2 F.4th 112 (3d Cir. 2021), on reh'g, 4 F.4th 204 (3d Cir. 2021) and reh'g granted, judgment vacated, 3 F.4th 605 (3d Cir. 2021) and aff'd, 4 F.4th 204 (3d Cir. 2021).

## § 29:126 CERCLA Defenses

Significantly, CERCLA provides for the imposition of strict and retroactive liability, which can also be joint.[1] This was done because CERCLA's focus is on the cleanup of sites contaminated with hazardous waste. Defenses under CERCLA are limited to the following:

(1) Acts of God;[2]
(2) Acts of war;
(3) "[A]n act or omission of a third party other than an employee or agent of the defendant, . . . if the defendant establishes by a preponderance of the evidence that (a) he exercised due care with respect to the hazardous substance concerned, . . . and (b) he took precautions against foreseeable acts or omissions of any such third party and the consequences that could foreseeably result from such acts or omissions";[3] or
(4) Any combination of (1), (2), or (3).[4]

These defenses are generally unsuccessful. In the oil and gas context, for example, courts have denied the "act of war" defense to oil companies who released hazardous substances during wartime while acting at the Government's direction.[5]

The petroleum exclusion has been characterized by courts as a "statutory exception" and not, technically speaking, an affirmative defense. This is true because the exclusion makes petroleum-related contamination "nonactionable for policy reasons even though such contamination might otherwise be actionable under CERCLA's general definition of 'hazardous material.' "[6]

In January of 2002, Congress enacted the Small Business Liability Relief and Brownfields Revitalization Act,[7] which amended CERCLA to provide liability limitations for the following:

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**[Section 29:126]**

[1]42 U.S.C. § 9601(32) ("The terms 'liable' or 'liability' under this subchapter shall be construed to be the standard of liability which obtains under section 311 of the Federal Water Pollution Control Act . . . ."); U.S. v. Alcan Aluminum Corp., 964 F.2d 252, 259, 35 Env't. Rep. Cas. (BNA) 1073, 22 Envtl. L. Rep. 21124 (3d Cir. 1992).

[2]CERCLA defines an "act of God" as "an unanticipated grave natural disaster or other natural phenomenon of an exceptional, inevitable, and irresistible character, the effects of which could not have been prevented or avoided by the exercise of due care or foresight." 42 U.S.C. § 9601(1). Courts have construed the "act of God" defense narrowly. *See* U.S. v. M/V Santa Clara I, 887 F. Supp. 825, 843, 41 Env't. Rep. Cas. (BNA) 1101, 1996 A.M.C. 910, 26 Envtl. L. Rep. 20264 (D.S.C. 1995) ("Even a poorly forecasted storm has been held under the Clean Water Act not to constitute an act of God because it was predicted and was avoidable."); U.S. v. Stringfellow, 661 F. Supp. 1053, 1061, 17 Envtl. L. Rep. 21134 (C.D. Cal. 1987) ("[T]he Court finds that the rains were not the kind of 'exceptional' natural phenomena to which the narrow act of God defense . . . applies. The rains were foreseeable . . . and any harm caused by the rain could have been prevented through design of proper drainage channels.").

[3]42 U.S.C. § 9607(b)(3).

[4]42 U.S.C. § 9607(b)(4).

[5]*See* U.S. v. Shell Oil Co., 294 F.3d 1045, 1061–62, 55 Env't. Rep. Cas. (BNA) 1052, 32 Envtl. L. Rep. 20783 (9th Cir. 2002).

[6]Nixon-Egli Equipment Co. v. John A. Alexander Co., 949 F. Supp. 1435, 1443, 27 Envtl. L. Rep. 20584 (C.D. Cal. 1996); *see further* Morgan v. Exxon Corp., 869 So. 2d 446, 452, 159 O.G.R. 829 (Ala. 2003) ("we disagree with those cases that have required the defendant to prove the applicability of the petroleum exclusion").

[7]Small Business Liability Relief and Brownfields Revitalization Act, Pub. L. No. 107-118, 115 Stat. 2356 (2002).

(1) Bona fide prospective purchasers (BFPPs);[8]
(2) Contiguous property owners (CPOs);[9] or
(3) Innocent landowners (ILOs).[10]

While an extensive discussion of these protections is beyond the scope of this chapter, parties who seek these protections are required to perform "all appropriate inquiries" into property before acquisition; and, for BFPPs and CPOs, must demonstrate no "affiliation" with a liable party.[11]

There are also several common continuing obligations, as detailed by the EPA in a recent guidance memo entitled *Enforcement Discretion Guidance Regarding Statutory Criteria for Those Who May Qualify as CERCLA Bona Fide Prospective Purchasers, Contiguous Property Owners, or Innocent Landowners*:[12]

- "Demonstrating that no disposal of hazardous substances occurred at the facility after acquisition by the landowner (for BFPPs and ILOs)";
- "Complying with land use restrictions and not impeding the effectiveness or integrity of institutional controls";
- "Taking 'reasonable steps' with respect to hazardous substance releases affecting a landowner's property";
- "Providing cooperation, assistance, and access to persons authorized to conduct response actions or natural resource restoration";
- "Complying with information requests and administrative subpoenas (for BFPPs and CPOs)"; and
- "Providing legally required notices (for BFPPs and CPOs)."[13]

One example of the attempted use of the innocent landowner defense in the context of petroleum contamination occurred in *Washington v. Time Oil Co*.[14] There, the court held that the innocent landowner defense was not available where (1) contaminants found on the property "were found in amounts in excess of the amounts that would have occurred in petroleum during the oil refining process" and (2) other "substances found on the property would not have occurred due to the refining process."[15] Because of this, the petroleum exclusion could not effectively shield the defendant from liability.[16]

## § 29:127 Penalties for CERCLA violations

A liable party under CERCLA is responsible for all costs of response (cleanup and

[8]The BFPP, found in CERCLA § 107(r), protects a party from liability if the party acquires property after January 11, 2002 and meets the criteria in CERCLA §§ 101(40) and 107(r).

[9]CERCLA § 107(q).

[10]*See* CERCLA § 107(b)(3) and CERCLA § 101(35); Superfund Amendments and Reauthorization Act of 1986 (SARA), Pub. L. No. 99-499, 100 Stat. 1613 (1986).

[11]Pub. L. No. 107-118, § 222(a)(B), (H).

[12]Memorandum from Susan Parker Bodine, EPA Assistant Administrator for Enforcement & Compliance, to Regional Counsels, Superfund National Program Managers (July 29, 2019), https://www.epa.gov/sites/production/files/2019-08/documents/common-elements-guide-mem-2019.pdf.

[13]Memorandum from Susan Parker Bodine, EPA Assistant Administrator for Enforcement & Compliance, to Regional Counsels, Superfund National Program Managers (July 29, 2019) at 2, https://www.epa.gov/sites/production/files/2019-08/documents/common-elements-guide-mem-2019.pdf.

[14]State of Wash. v. Time Oil Co., 687 F. Supp. 529, 531, 27 Env't. Rep. Cas. (BNA) 2076, 18 Envtl. L. Rep. 21376 (W.D. Wash. 1988).

[15]State of Wash. v. Time Oil Co., 687 F. Supp. 529, 531, 532, 27 Env't. Rep. Cas. (BNA) 2076, 18 Envtl. L. Rep. 21376 (W.D. Wash. 1988).

[16]State of Wash. v. Time Oil Co., 687 F. Supp. 529, 531, 27 Env't. Rep. Cas. (BNA) 2076, 18 Envtl. L. Rep. 21376 (W.D. Wash. 1988).

investigation) incurred by the United States, a State, or a Tribe "not inconsistent with the National Contingency Plan" (the CERCLA cleanup blueprint) or "necessary" costs of response incurred by any other person, to the extent affirmatively consistent with the NCP.[1] Additionally, defendants are responsible for natural resource damages (e.g., to wildlife, habitat, waters, etc.).[2]

CERCLA provides for a range of penalties for violations, which the EPA may adjust to account for inflation.[3] If a liable party "fails without sufficient cause to properly provide removal or remedial action upon order of the President pursuant to section 9604 or 9606 of this title," that party may be also held to be liable "for punitive damages in an amount at least equal to, and not more than three times, the amount of any costs incurred by the Fund as a result of such failure to take proper action."[4]

In addition to significant fines, criminal penalties of three years imprisonment (up to five years for second or subsequent convictions), are possible for notification failures.[5] Any person in charge of a facility or vessel who fails to immediately notify the appropriate agency of the U.S. Government as soon as that person became aware of the release into the environment of a hazardous substance in an amount equal to or great than a reportable quantity without a federal permit may be subject to such penalties.[6]

### § 29:128 Conclusion

Given the potentially broad reach of CERCLA liability, which has been described as "a black hole that indiscriminately devours all who come near it,"[1] parties in the oil and gas industries should be aware of the limits of the petroleum exclusion and reporting requirements applicable to specific situations.

## F. CLEAN AIR ACT

### § 29:129 Generally

The federal Clean Air Act (CAA) imposes permitting (both preconstruction and operating) obligations and technical standard on oil and gas operations. States are often the primary regulator under the CAA, based on delegated authority from the U.S. Environmental Protection Agency (EPA). While states are only required to meet federal minimum standards, they have significant discretion in how they implement their programs and what limits they set. This can lead to dramatic differences in permitting and operational requirements applicable to the same oil and gas operations in different states. Permitting requirements also vary based on the emissions associated with a source. Typically, oil and gas operations are considered

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**[Section 29:127]**

[1] 42 U.S.C. § 9607(4); U.S. v. Chapman, 146 F.3d 1166, 1170, 28 Envtl. L. Rep. 21392 (9th Cir. 1998).

[2] 42 U.S.C. § 9607(4)(C).

[3] *See* Civil Monetary Penalty Inflation Adjustment, 85 Fed. Reg. 83818 (Dec. 23, 2020) (to be codified at 40 C.F.R. § 19).

[4] 42 U.S.C. § 9607(c)(3).

[5] 42 U.S.C. § 9603(b); U.S. EPA, *Penalties for Failure to Report a Release*, https://www.epa.gov/epcra/penalties-failure-report-release (last visited June 29, 2021).

[6] 42 U.S.C. § 9603(b); *Penalties for Failure to Report a Release*, *supra* note 73.

**[Section 29:128]**

[1] Long Beach Unified School Dist. v. Dorothy B. Godwin California Living Trust, 32 F.3d 1364, 1366, 93 Ed. Law Rep. 1163, 39 Env't. Rep. Cas. (BNA) 1065, 24 Envtl. L. Rep. 21279 (9th Cir. 1994) (citation omitted).

"minor sources," which qualifies them for more streamlined permits. The CAA also imposes requirements related to the accidental release of certain substances, but oil and gas operations are generally exempt from these requirements.

### § 29:130 Cooperative federalism under the Clean Air Act

The CAA is administered by the EPA, in coordination with state, local, and tribal governments. At the federal level, the EPA promulgates National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. Specifically, the NAAQS establish standards for six criteria pollutants (carbon monoxide, lead, nitrogen oxide, ozone, particulate matter, and sulfur dioxide) that must be met in all states.

Although EPA establishes federal standards, much of the implementation is left to the states. In fact, the CAA statute establishes that "air pollution prevention . . . is the primary responsibility of States and local governments."[1] Accordingly, states have the ability to determine how to achieve those standards and meet the associated requirements within their own borders. As the U.S. Supreme Court noted shortly after the implementation of the CAA, provided that a state's choice of emission limitations is compliant with the NAAQS, "the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation."[2]

States regulate air pollution within their borders by promulgating and enforcing State Implementation Plans or "SIPs." A SIP is the overall body of regulations that governs air emissions in the state. In some cases, a tribal government will also implement its own body of regulations, referred to as a Tribal Implementation Plan or "TIP." EPA has responsibility for reviewing and approving SIPs and TIPs that meet the NAAQs. If a state fails to submit a SIP or the SIP does not fully comply with the NAAQS, EPA will issue a federal implementation plan or "FIP" to ensure that the state complies with the relevant NAAQS. EPA may also develop FIPs for tribal lands if the tribe does not adopt its own implementation plan. Currently, EPA oversees a handful of FIPs spread across several states and tribal governments. For example, EPA administers a FIP for the Fort Berthold Indian Reservation that focuses on emissions from upstream oil and gas operations. This FIP establishes requirements to reduce emissions of volatile organic compounds (VOCs) from well completions, recompletions, and production and storage operations.[3]

### § 29:131 Preconstruction Permitting

The CAA requires operators to obtain a preconstruction permit before commencing construction or operation of a source as part of New Source Review (NSR) permitting. NSR permitting falls into one of three categories: (1) prevention of significant deterioration (PSD) permitting for construction of a "major source" or "major modification" within an area that meets all NAAQS; (2) nonattainment NSR permitting for construction of "major sources" or "major modifications" in areas that do not meet all NAAQS; and (3) minor NSR permitting for those sources that do not trigger PSD or nonattainment NSR permitting (*i.e.,* for sources or modifications that do not meet the "major" thresholds). In the oil and gas segment, operators are required to permit emissions from air emitting equipment associated with their activities, including but not limited to storage tanks, engines, flares and other

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**[Section 29:130]**

[1] 42 U.S.C. § 7401(a)(3).

[2] Train v. Natural Resources Defense Council, Inc., 421 U.S. 60, 79, 95 S. Ct. 1470, 43 L. Ed. 2d 731, 7 Env't. Rep. Cas. (BNA) 1735, 5 Envtl. L. Rep. 20264 (1975).

[3] *See* 40 C.F.R. § 49.4161 (2021).

combustion devices, compressors, and heater treaters.

EPA's regulations establish the federal NSR permitting requirements and set the minimum requirements for state permitting programs to receive approval under the state SIP. States or tribes may assume delegation of NSR permitting pursuant to their SIP or TIP. Once a state or tribe receives delegation, it takes responsibility for issuing preconstruction permits. At that point, the state or tribe may implement its own unique (and sometimes more stringent) permitting requirements, provided they meet EPA's basic requirements. If the state or tribe fails to develop a SIP or TIP that establishes delegation of NSR permitting, EPA retains responsibility for permitting. EPA currently has authority to issue nonattainment, PSD, and minor NSR permits on tribal lands.[1]

For PSD permitting, a "major source" generally refers to new facilities that have the potential to emit 250 tons per year (tpy) or more of a pollutant. EPA regulations establish a major source threshold of 100 tpy for 28 named sources, with 250 tpy the relevant threshold for unnamed sources.[2] Although the 28 named sources include petroleum refineries and certain petroleum storage and transfer units, they do not cover typical upstream oil and gas operations. Accordingly, the 250 tpy threshold is relevant for oil and gas operations.

A "major modification" is a physical change or change in the method of operation at a major stationary source that results in a net significant increase in criteria emissions above defined modification thresholds.[3] The thresholds for a major modification vary from 0.6 tpy to 100 tpy based on the pollutant.[4]

New major sources and major modifications in nonattainment areas (those that do not meet all NAAQS) are subject to a similar permitting program. However, the thresholds for what constitutes a major source and major modifications are lower than the thresholds applicable to PSD permitting.[5]

Both PSD and nonattainment NSR permitting processes require a Best Available Control Technology (BACT) evaluation.[6] For PSD permitting, this requires a case-by-case analysis of the available control technologies for the pollutant and the source. These control technologies are ranked by effectiveness, but technologies that are technically infeasible or economically unreasonable may be excluded.[7] In contrast, the BACT review for nonattainment NSR permitting is subject to a heightened standard that does not consider costs.[8]

Finally, minor NSR permitting applies when a source does not meet the major source or major modification thresholds of PSD and nonattainment NSR permitting. States take a variety of approaches to minor NSR permitting. However, in some cases, states have established a one-size approach for these minor sources, rather than requiring an individual case-by-case permit. For example, Texas allows operators to claim a permit by rule (PBR) for certain facilities that have emissions below

**[Section 29:131]**

[1] *See* 76 Fed. Reg. 38748, 38753 (July 1, 2011).

[2] 40 C.F.R. § 51.166(b)(1)(i) (2021).

[3] 40 C.F.R. § 51.166(b)(2)(i) (2021).

[4] 40 C.F.R. § 51.166(b)(23)(i) (2021).

[5] 40 C.F.R. § 51.165(a)(iv)(A) (2021).

[6] *See* U.S. EPA, *New Source Review Workshop Manual,* https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf (last visited June 25, 2021).

[7] U.S. EPA, *New Source Review Workshop Manual,* https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf (last visited June 25, 2021).

[8] U.S. EPA, *New Source Review Workshop Manual,* https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf (last visited June 25, 2021).

25 tpy of VOCs and can satisfy a suite of other requirements.[9] Operators can claim PBRs for oil and gas production facilities, temporary oil and gas facilities, flares, and other upstream oil and gas operations or equipment. Similarly, operators may permit oil and gas minor sources in New Mexico using a general construction permit for oil and gas facilities, which is available for sources with VOC emissions below 95 tpy.[10]

Preconstruction permits must generally be obtained prior to construction and startup of oil and gas facilities. However, oil and gas exploration and production activities can present unique issues related to estimating emissions for permit applications. In contrast to those sources with generally consistent emissions as part of normal operations, production rates and the resulting emissions from wells often dramatically decline following startup. As a result, operators may not be able to precisely estimate annual emissions until after the startup of an oil or gas well. To address this relative uncertainty, states have established permitting programs that allow operators to secure preconstruction authorization based on initial estimates that they can then refine based on actual production data. For example, minor source wells in North Dakota's Bakken Pool may submit a well registration rather than a preconstruction permit.[11] The well registration is not required to be submitted until 90 days following the first date of production, which gives the operator time to develop more accurate emissions estimates based on the first month of production activity. At the same time, the registration requires the operator to establish enforceable emissions limitations and commit to certain emission control requirements.

## § 29:132 Title V Permitting

Title V of the CAA establishes the requirement for operating permits. These operating permits (referred to as Title V Permits) are designed to consolidate all applicable air quality requirements—both emissions limits and monitoring methods for demonstrating compliance with those limits—into one permit. All sources with the potential to emit 100 tpy or more of a regulated pollutant or combination of pollutants are required to obtain a Title V permit.[1] Title V permits are generally issued by delegated state authorities. However, as with other permits and air quality regulations, EPA implements a federal program if the state fails to do so. All operators with Title V permits must submit a deviation report identifying noncompliance with the many terms of the permit every six months and submit an annual certification of their compliance with the conditions of the permit.[2]

## § 29:133 Technology-Based Standards

The CAA also requires that EPA develop technology-based standards for specific categories of stationary sources. These New Source Performance Standards (NSPS) apply to new, modified, and reconstructed facilities. One example within upstream

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[9] *See* 30 T.A.C. § 106.4(a).

[10] *See* N.M. Env't Dep't, *Air Quality Bureau General Construction Permit for Oil and Gas Facilities GCP-Oil & Gas* (Apr. 27, 2018), https://www.env.nm.gov/wp-content/uploads/sites/2/2018/06/GCP-Oil-Gas-Final-002.pdf.

[11] *See* N.D. Dep't of Health, *Bakken Pool Oil and Gas Production Facilities Air Pollution Control Permitting & Compliance Guidance* (May 2, 2011), *available at* https://deq.nd.gov/publications/AQ/policy/PC/20110502_OilGas_Permitting_Guidance.pdf.

**[Section 29:132]**

[1] 42 U.S.C. § 7661(2).

[2] *See* Tex. Comm'n on Env't Quality, *Title V Deviation Reporting and Compliance Certification,* at 2 (Nov. 2012).

operations is NSPS OOOOa. The NSPS OOOOa standard applies EPA's "best system of emissions reduction" for reducing emissions of greenhouse gases and VOCs across a number of emissions sources in the oil and natural gas source category, including wells, compressors, pneumatic controllers, storage vessels, and collections of fugitive components.[1] This includes the use of reduced emission completions and completion combustion devices for well completion operations and semiannual monitoring and repairs for fugitive emissions from well sites and compressor stations.[2]

States may also impose technology-based standards for new sources through the BACT analysis discussed above. In addition, the CAA requires that SIPs for nonattainment areas include reasonably available control technology (RACT) requirements for existing sources.[3] RACT is the "lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available, considering technological and economic feasibility."[4] States and tribal authorities make their own determination as to what constitutes RACT for a specific source category. As is often the case with state implementation, states will sometimes impose more stringent requirements than the federal equivalent. For example, Colorado's Regulation 7 imposes control requirements for VOC emissions that are more stringent than those found in NSPS OOOOa.[5]

## § 29:134 Greenhouse Gas Regulation

In addition to technology-based standards, EPA requires annual greenhouse gas emission reporting under NSPS Subpart W. Pursuant to NSPS Subpart W, owners and operators of onshore and offshore oil and gas operations must report data concerning their greenhouse gas emissions for production, processing, transmission, and distribution facilities.[1] The emissions estimates must include emissions from equipment leaks identified during leak inspections that track those required under NSPS OOOOa.[2]

President Biden's stated commitment to addressing climate change and the country's reentry into the Paris Agreement (an international agreement focused on reducing climate change), will likely spur new regulatory initiatives by the EPA. In addition, individual states have recently taken steps to advance greenhouse gas regulation from oil and gas activities. For example, in January 2019, the governor of New Mexico signed an executive order that includes a goal of reducing statewide greenhouse emissions by at least 45% by 2030 and directed the state environmental and oil and gas regulatory agencies to jointly develop a statewide, enforceable regulatory framework to secure reductions in oil and gas sector methane emissions.

## § 29:135 Risk management plan

Section 112(r) of the CAA requires that EPA establish regulations to prevent the accidental release and minimize the consequence of the release of certain listed sub-

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**[Section 29:133]**

[1] 81 Fed. Reg. 35824, 35825 (June 3, 2016).

[2] 81 Fed. Reg. 35824, 35825 (June 3, 2016).

[3] 42 U.S.C. § 7502(c)(1).

[4] *See* 44 Fed. Reg. 53761, 53762 (Sept. 17, 1979).

[5] *See* 5 C.C.R. 1001-9 (2021).

**[Section 29:134]**

[1] *See* 40 C.F.R. § 98.231 (2021).

[2] 40 C.F.R. § 98.234 (2021).

stances and other extremely hazardous substances.[1] To effectuate this mandate, EPA's risk management plan (RMP) regulations at 40 C.F.R. Part 68 establish requirements for operators to develop and implement a risk management program if they have any processes at their facilities that meet or exceed certain threshold quantities of flammable or toxic chemicals. Facilities must submit a facility-specific RMP and revise the RMP every five years.[2] This submittal includes assessments of offsite consequences, potential worst-case releases, accident history, release prevention, and emergency planning.[3] Facilities are also subject to additional requirements depending on their program level, which is assessed based on the level of risk associated with their processes.[4] However, as discussed in more detail in Section 29:172 below, upstream oil and gas operations are generally excluded from RMP regulation under an exemption for naturally occurring hydrocarbons.

In addition to EPA's RMP regulations, § 112(r) of the CAA establishes a general duty, often referred to as the "general duty clause." The provision states that "owners and operators of stationary sources producing, processing, handling or storing such substances have a general duty in the same manner and to the same extent as section 654 of title 29 to identify hazards which may result from such releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur."[5] EPA has taken the position that the general duty clause applies to any facility that uses a regulated substance or other extremely hazardous substance in "any amount."[6] In other words, even a facility with less than a threshold quantity of a flammable substance or toxic chemical that is otherwise excluded from the RMP regulations can be cited for a violation of the general duty clause. EPA often uses this general duty clause as the basis for enforcement actions following industrial incidents.

## § 29:136 Enforcement

The CAA also provides robust authority for EPA to take enforcement action against any person who violates CAA requirements. EPA may seek administrative, civil, or criminal penalties, the cost of which can be substantial. Although the CAA sets statutory maximum civil and administrative penalties of up to $25,000 per violation per day, this amount has been increased over the years to adjust for inflation.[1] Currently, EPA can seek up to $48,762 per day in administrative penalties and up to $102,638 per day in civil penalties.[2]

In some cases, the injunctive relief associated with a CAA enforcement action can be more costly than the penalties themselves. In recent years, EPA has imposed broad injunctive obligations for upstream and midstream oil and gas operations. For example, in 2015 and the years following, EPA entered several consent decrees with exploration and production companies addressing alleged violations associated with

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**[Section 29:135]**

[1] 42 U.S.C. § 7412(r).

[2] 40 C.F.R. § 68.12 (2021).

[3] 40 C.F.R. § 68.12 (2021).

[4] 40 C.F.R. § 68.12 (2021).

[5] 42 U.S.C. § 7412(r).

[6] *See* U.S. EPA, *The General Duty Clause Fact Sheet*, at 2 (April 2020), https://www.epa.gov/sites/production/files/2013-10/documents/gdc-fact.pdf.

**[Section 29:136]**

[1] 42 U.S.C. § 7413(b).

[2] *See* 85 Fed. Reg. 83818, 83821 (Dec. 23, 2020).

emissions from storage tanks and vapor control systems. In addition to imposing millions of dollars in civil penalties and mitigation projects, these consent decrees also required operators to complete extensive engineering evaluations, third-party audits, inspections, and modifications to vapor control systems across thousands of tank batteries. EPA has also targeted midstream operations, with a focus on pigging operations in recent years. In 2018, EPA entered a consent decree with one operator that imposed over $600,000 in civil penalties and required injunctive relief (valued at approximately $2.6 million according to EPA's estimates) aimed at reducing emissions associated with pigging operations for compressor stations and stand-alone facilities in a natural gas gathering system.

## § 29:137 Carbon sequestration

In the wake of the Paris Agreement and continued focus on the impact of greenhouse gases from industry, including oil and gas operations, both public and private interests are looking more closely at carbon sequestration technologies. Carbon sequestration involves capturing carbon dioxide from emitting activities (power plants and other large industrial sources) and permanently storing it, typically via injection into deep subsurface formations. These subsurface formations can include depleted oil and gas reservoirs. For example, Texas statutes establish jurisdiction for the Railroad Commission of Texas—the state's primary oil and gas regulator—over wells used for the injection of carbon dioxide into a reservoir that is initially or may be productive of oil and gas.[1]

Utilization of carbon sequestration in the U.S. is still in the early stages, but there have been recent initiatives to deploy carbon sequestration at scale. In 2010, EPA issued a rule establishing minimum requirements for all aspects of the injection process for carbon sequestration as part of the Safe Drinking Water Act's Underground Injection Control (UIC) program.[2] These requirements covered permitting, geologic site characterization, well construction, operation, mechanical integrity testing, plugging, and site closure.[3] Although the rule was primarily designed to protect drinking water resources, EPA's statements at the time it published the rules identified the potential benefits of carbon sequestration. Specifically, EPA noted that although carbon sequestration "is occurring now on a relatively small scale, it could play a larger role in mitigating greenhouse gas (GHG) emissions from a wide variety of stationary sources" and "even if only a fraction of [the US] geologic capacity is used, [carbon sequestration] would play a sizeable role in mitigating US GHG emissions."[4] To date, there have been only six carbon sequestration well permits issued and only two wells exist. But tax credit incentives, government-funded research, an increase in corporate commitments to carbon neutrality, and anticipated market opportunities have converged to create a recent surge in interest in carbon sequestration projects.

In 2017, Secretary of Energy Rick Perry requested that the National Petroleum Council (NPC) provide advice concerning carbon capture, use, and storage (CCUS).[5] In response, the NPC released a report in late 2019 that determined the US is "uniquely positioned" and has "substantial capability" to drive widespread deploy-

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**[Section 29:137]**

[1] *See* Tex. Water Code § 27.041.

[2] 75 Fed. Reg. 77230, 77233 (Dec. 10, 2010).

[3] 75 Fed. Reg. 77230, 77233 (Dec. 10, 2010).

[4] 75 Fed. Reg. 77234 (Dec. 10, 2010).

[5] Nat'l Petroleum Council, *Meeting the Dual Challenge a Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*, at 1-2 (2019), https://dualchallenge.npc.org/ (last visited June 28, 2021).

ment of CCUS technology.[6] The NPC determined that the expansion potential for CCUS depends in part on improving financial incentives and further developing the regulatory framework.[7]

### G. OIL POLLUTION ACT

#### § 29:138 Introduction

The Oil Pollution Act (OPA)[1] was enacted in 1990 in response to the *Exxon Valdez* oil spill in Prince William Sound, Alaska.[2] OPA imposes strict and limited liability on the owners and operators of vessels, oil producing and handling facilities, and pipelines for discharges or substantial threats of discharges of oil into navigable waters, adjoining shorelines, and the exclusive economic zone.[3] "Oil" is defined as "oil of any kind or in any form, including petroleum [and] fuel oil," but exclusive of listed or designated hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA).[4] Prior to the enactment of OPA, federal liability for marine oil spills was governed by the Clean Water Act (CWA).

#### § 29:139 *Exxon Valdez*

On March 24, 1989, the crude oil tank vessel *Exxon Valdez* ran aground on the Bligh Reef in Prince William Sound, Alaska. The *Exxon Valdez* carried over one million barrels of crude oil, supplied from the Trans-Alaska Pipeline connected to producing fields in Alaska's North Slope, and bound for refineries on the West Coast.[1] The single-hulled vessel was breached, causing a release of over 260,000 barrels of crude which, at the time, was the largest oil spill in U.S. history. After extensive cleanup efforts in the unique ecosystem of the Sound, images of which remain indelible to practitioners and the public alike over 30 years later, Exxon was eventually liable for $2.1 billion in restitution and other fines. This included $125 million in fines under the CWA and hundreds of million more under a consent decree with the United States and the State of Alaska.[2]

Just a few months later, the Senate Environment and Public Works Committee approved the bill that would become OPA,[3] finding that the *Exxon Valdez* spill, as well as three other significant spills across the lower-48 in the same year, "have demonstrated that oil pollution from accidental tanker spills is a real and continuing threat to the public health and welfare and the environment. The disaster

[6] Nat'l Petroleum Council, *Meeting the Dual Challenge a Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*, at 8 (2019), https://dualchallenge.npc.org/ (last visited June 28, 2021).

[7] Nat'l Petroleum Council, *Meeting the Dual Challenge a Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*, at 8 (2019), https://dualchallenge.npc.org/ (last visited June 28, 2021).

**[Section 29:138]**

[1] 33 U.S.C. §§ 2701 to 2762.

[2] While the incident was a major precipitating event, commentators have observed that OPA "is actually the product of nearly 20 years of Congressional debate on oil pollution liability and tanker safety." GOV'T INSTITUTES, ENVT'L LAW HANDBOOK 222 (12th ed. 1993).

[3] 33 U.S.C. §§ 2702(a), 2701(32)(A) to (F).

[4] 42 U.S.C. §§ 9601 et seq.

**[Section 29:139]**

[1] Exxon Shipping Co. v. Baker, 554 U.S. 471, 476, 128 S. Ct. 2605, 171 L. Ed. 2d 570, 66 Env't. Rep. Cas. (BNA) 1545, 2008 A.M.C. 1521 (2008); DAVID LEBEDOFF, CLEANING UP 1 (Free Press 1997).

[2] *Exxon Shipping Co. v. Baker*, 554 U.S. at 479.

[3] S. 686, 101st Cong. (1989).

caused by the nation's largest oil spill in Prince William Sound was exacerbated greatly by an unreasonably slow, confused and inadequate response by industry and government that failed miserably in containing the spill and preventing damage."[4]

### § 29:140 Liability

OPA imposes strict liability on a "responsible party" for removal costs and damages resulting from a release or threatened release. A "responsible party" is generally the owner or operator of a vessel, facility, or pipeline. Multiple responsible parties (*e.g.*, the owner and charterer of a vessel) may be jointly and severally liable.[1] Responsible parties are liable for removal costs, including costs incurred by federal, state, and tribal governments.[2] Responsible parties are also liable for natural resource damages, damages to property, and loss of profits and earning capacity, among other costs.[3]

In circumstances not involving gross negligence, willful misconduct, violation of federal regulation, or failure to report or assist with a spill,[4] OPA liability is limited based on the type of facility from which the discharge occurs. Statutory liability for discharges from tank vessels is limited to the greater of $1,900 per gross ton, or $4 million for vessels 3,000 gross tons or smaller or $16 million for larger vessels.[5] For discharges from offshore facilities (such as offshore oil wells), excluding deepwater ports, the limit is $75 million plus removal costs.[6] For discharges from onshore facilities (such as refineries and pipelines) and deepwater ports, liability is limited to $350 million.[7] For discharges from mobile offshore drilling units (MODUs), the limits for vessels apply, unless removal costs and damages exceed the applicable vessel liability limits, in which case the offshore facility limits apply.[8]

OPA gives the president the ability to adjust liability limits for every type of facility discharge except discharges from vessels,[9] but he or she shall adjust limits for all facility spills to reflect increases in the Consumer Price Index.[10] And unlike the pre-OPA CWA framework applicable to oil spills, "any person," not just the federal government, can recover costs and damages from responsible parties.[11]

Responsible parties can assert certain defenses to liability. OPA provides three complete statutory defenses that a responsible party may assert: an act of God, act of war, and act or omission of a third party other than the responsible party's em-

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[4] S. Rep. No. 101-94, at 2 (1989).

**[Section 29:140]**

[1] *See* Gov't Institutes, Envt'l Law Handbook, Twelfth Ed. 225.

[2] 33 U.S.C. § 2702(b)(1).

[3] 33 U.S.C. § 2702(b)(2).

[4] 33 U.S.C. § 2704(c)(1) to (2).

[5] 33 U.S.C. §§ 2704(a)(1)(B), (C)(ii)(II), (C)(i)(II). Higher limits exist for single-hull tank vessels, like *Exxon Valdez*, but OPA directed that single-hull tank vessels be phased out by 2015. 46 U.S.C. § 3703a(c)(4).

[6] 33 U.S.C. § 2704(a)(3).

[7] 33 U.S.C. § 2704(a)(4).

[8] 33 U.S.C. § 2704(b).

[9] 33 U.S.C. § 2704(d).

[10] 33 U.S.C. § 2704(d)(4). These limits have been adjusted several times. *See, e.g.,* Consumer Price Index Adjustments of Oil Pollution Act of 1990 Limits of Liability—Vessels, Deepwater Ports and Onshore Facilities, 84 Fed. Reg. 39970 (Aug. 13, 2019).

[11] 33 U.S.C. § 2702(b)(1)(B). Under the CWA, only the Federal government could recover removal costs. Cong. Research Serv., Oil Pollution Act of 1990 (OPA): Liability of Responsible Parties 1 (June 2, 2010).

ployee or agent.[12] A fourth defense is also available with respect to particular claimants who can be shown to have caused a discharge through their own gross negligence or willful misconduct.[13] While facts will vary from incident to incident, as a general matter, these defenses can be fairly limited. For example, as a statutory threshold to asserting any of the complete defenses, a responsible party must have complied with other obligations under OPA, including release reporting requirements, compliance with removal orders, and compliance and assistance with cleanup efforts.[14] In addition, third party liability cannot be asserted as a defense if the third party's act or omission occurred in connection with a contractual relationship with a responsible party,[15] or if the responsible party failed to exercise due care or failed to take precautions as to foreseeable actions by the third party.[16]

Importantly, OPA's liability limits do not preempt state laws regarding oil spill liability or financial responsibility.[17] Responsible parties can therefore be liable under both OPA and state law equivalents for the same discharge.

## § 29:141 Oil Spill Response

OPA amended existing provisions in the CWA regarding the National Contingency Plan (NCP) and individual facility oil spill response plans.[1] The NCP, overseen and implemented by the U.S. Environmental Protection Agency and the U.S. Coast Guard, is a comprehensive plan for oil spill response and removal that divides response efforts into nationwide regional teams and coordinates efforts among 16 federal agencies. Individual response efforts are led by a single designated Federal On-Scene Coordinator.[2]

Vessels and onshore and offshore oil facilities are also required to prepare and maintain individual facility oil spill response plans that are consistent with the NCP.[3] For example, tank vessel spill response plans must include a list of contacts, shore-based response activities, training and exercise procedures, and plan review and update procedures.[4] Responsible parties may not assert acts in accordance with individual spill response plans as a defense to OPA liability.[5]

OPA also firmly established the Oil Spill Liability Trust Fund (OSLTF) by fully funding and authorizing expenditures from a fund established by Congress (but never used) in 1986.[6] The OSLTF is available to pay removal costs incurred by governments and uncompensated damages claims,[7] up to a limit of $1 billion per incident.[8] The primary source of funding for the OSLTF is a per-barrel tax imposed

[12] 33 U.S.C. § 2703(a)(1) to (3).

[13] 33 U.S.C. § 2703(b).

[14] 33 U.S.C. § 2703(c).

[15] 33 U.S.C. § 2703(a)(3)(A). This requirement does not apply to releases of oil transported by rail.

[16] 33 U.S.C. § 2703(a)(3)(A).

[17] 33 U.S.C. §§ 2718(a), 2719.

**[Section 29:141]**

[1] 33 U.S.C. § 1321(j).

[2] AMER. PETROLEUM INST., "OIL SPILL RESPONSE PLANNING," *available at* https://www.oilspillprevention.org/oil-spill-preparedness/oil-spill-response-planning. *See also* 40 C.F.R. pt. 300 (2021).

[3] 33 U.S.C. § 1321(j)(5).

[4] 33 C.F.R. § 155.1030 (2021).

[5] 33 U.S.C. § 1321(j)(5)(H).

[6] 26 U.S.C. § 9509; 33 U.S.C. §§ 2701(11), 2712.

[7] 33 U.S.C. § 2712(a)(1) to (4).

[8] 26 U.S.C. § 9509(c)(2)(A).

on crude oil imported into, exported from, or consumed in the United States.[9] The OSLTF can also recover removal costs from responsible parties.[10] Between FY2007 and FY2018, appropriations from the OSLTF totaled $3.37 billion. In addition to excise tax receipts, the OSLTF collected $2.13 billion from OPA fines and penalties and $1.28 billion in other cost recovery.[11] This includes $2.1 billion collected following the *Deepwater Horizon* incident, which is expected to generate an additional $76 million in receipts through 2031.[12]

### § 29:142 *Deepwater Horizon*

On April 20, 2010, the MODU *Deepwater Horizon*, owned by Transocean Ltd., experienced a loss of well control while operating above BP's Macondo offshore oil well in the U.S. Gulf of Mexico, resulting in an explosion and fire aboard the dynamically-positioned drilling vessel. The vessel eventually sank, laden with nearly 700,000 gallons of diesel fuel, and causing a subsea release of more than 4 million barrels of crude oil from the Macondo well[1] that was not brought under control for 87 days after the subsea blowout preventer failed to stop the flow of oil from the well.[2] It was the largest oil spill by volume in U.S. history.

In ensuing Multi-District Litigation, involving hundreds of claimants and consolidated in the Eastern District of Louisiana, the Court found that both BP and Transocean were responsible parties under OPA. With respect to the subsurface discharge of oil from the Macondo well, BP was the responsible party because the Court found that the MODU was operating as an "offshore facility" at the time of the discharge, in which case OPA defines the offshore lessee as the responsible party.[3] Transocean was also found to be a responsible party for removal costs as an "operator" of an offshore facility.[4] The Court apportioned OPA's joint and several liability in the amounts of 67% to BP and 30% to Transocean.[5] In addition, the Court found that OPA's liability limits did not apply on grounds that failures in well construction violated applicable federal regulations.[6]

While the previous largest U.S. oil spill, *Exxon Valdez*, spurred the enactment of

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[9] 26 U.S.C. § 4611(a) to (b).

[10] 33 U.S.C. § 2715(c).

[11] CONG. RESEARCH SERV., THE OIL SPILL LIABILITY TRUST FUND TAX: BACKGROUND AND REAUTHORIZATION ISSUES IN THE 116TH CONGRESS 2 (April 3, 2019).

[12] CONG. RESEARCH SERV., THE OIL SPILL LIABILITY TRUST FUND TAX: BACKGROUND AND REAUTHORIZATION ISSUES IN THE 116TH CONGRESS 2 (April 3, 2019).

**[Section 29:142]**

[1] NAT'L COMM'N ON THE BP DEEPWATER HORIZON OIL SPILL AND OFFSHORE DRILLING, "DEEP WATER: THE GULF OIL DISASTER AND THE FUTURE OF OFFSHORE DRILLING" (2011), at 130, 1.

[2] In re Oil Spill by Oil Rig Deepwater Horizon in Gulf of Mexico, on April 20, 2010, 21 F. Supp. 3d 657, 667, 2014 A.M.C. 2113 (E.D. La. 2014). Judge Barbier's opinion provides an excellent and concise description of the complex technical facts that led to the blowout and explosion.

[3] In re Oil Spill by Oil Rig Deepwater Horizon in Gulf of Mexico, on April 20, 2010, 21 F. Supp. 3d 657, 754 and n.283, 2014 A.M.C. 2113 (E.D. La. 2014). BP was also subject to enhanced civil penalties under the CWA for gross negligence and willful misconduct. In re Oil Spill by Oil Rig Deepwater Horizon in Gulf of Mexico, on April 20, 2010, 21 F. Supp. 3d 657, 754, 757 and n.283, 2014 A.M.C. 2113 (E.D. La. 2014).

[4] In re Oil Spill by Oil Rig Deepwater Horizon in Gulf of Mexico, on April 20, 2010, 21 F. Supp. 3d 657, 756, 2014 A.M.C. 2113 (E.D. La. 2014); 33 U.S.C. § 2704(c)(3).

[5] In re Oil Spill by Oil Rig Deepwater Horizon in Gulf of Mexico, on April 20, 2010, 21 F. Supp. 3d 657, 757, 2014 A.M.C. 2113 (E.D. La. 2014). The remaining 3% was assigned to Halliburton, a contractor providing cementing services at the Macondo well, under general maritime law. In re Oil Spill by Oil Rig Deepwater Horizon in Gulf of Mexico, on April 20, 2010, 21 F. Supp. 3d 657, 757, 2014 A.M.C. 2113 (E.D. La. 2014).

[6] In re Oil Spill by Oil Rig Deepwater Horizon in Gulf of Mexico, on April 20, 2010, 21 F. Supp. 3d

OPA, the *Deepwater Horizon* incident did not result in major changes to federal statutes. But it did precipitate major changes in other areas, including the reorganization of Department of the Interior (DOI) agencies responsible for offshore oil and gas operations,[7] as well as the creation of industry-led safety initiatives such as the Helix Well Containment Group and the Center for Offshore Safety. These changes were intended to separate revenue collection and industry regulation functions in federal oversight, and to augment industry's ability to prevent and respond to major offshore spill incidents.

## § 29:143 Other Major U.S. Oil Spill Incidents

- ***Santa Barbara Oil Spill.*** Prior to the *Deepwater Horizon* incident, the largest offshore oil spill incident in the U.S. occurred offshore California in 1969. A Union Oil platform in the Santa Barbara channel experienced a blowout that released at least 80,000 barrels of crude. While the blowout preventer functioned as intended, unlike during the *Deepwater Horizon* incident, crude continued to flow through fissures in the seabed as a result of the well being permitted at a shallower than typical depth.[1] Like *Deepwater Horizon*, no major statutory changes specific to oil spills were enacted in the immediate wake of the incident, but the spill and resulting images of slicks along beaches catalyzed significant changes in offshore oil regulation, including a temporary offshore drilling moratorium and enactment of new offshore regulations.[2] The incident may also have contributed to Congressional action in the form of the National Environmental Policy Act, enacted in 1970.[3]
- ***Athos I.*** In 2004, the tank vessel *Athos I* was laden with heavy Venezuelan crude oil when it struck an abandoned and uncharted anchor in the Delaware River en route to a refinery in Paulsboro, New Jersey.[4] The anchor punctured the single-hulled vessel, resulting in a discharge of over 6,000 barrels of crude into the river. While the owner of the *Athos I* was found to be the responsible party and subject to OPA's liability limits, the U.S. Supreme Court was asked to resolve a related contract dispute regarding the scope of a "safe berth" provision in the vessel's charter agreement and whether the presence of the anchor in the river affected its application. The Court found that the safe berth provision imposed a warranty of safety, which shifted contractual liability to the

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657, 754-55, 2014 A.M.C. 2113 (E.D. La. 2014); 33 U.S.C. § 2704(c)(1)(B); 30 C.F.R. § 250.420(a)(2) (2021) (Department of the Interior regulation regarding cementing and casing of offshore wells).

[7]Pre-Macondo, the Minerals Management Service ("MMS") was responsible for offshore permitting, safety, and collection of royalty revenue. Following the incident, MMS was reorganized as the Bureau of Ocean Energy Management, Regulation, and Enforcement; and, later, as the Bureau of Ocean Energy Management (responsible for permitting), the Bureau of Safety and Environmental Enforcement (responsible for operations), and the Office of Natural Resources Revenue (responsible for royalty collection).

**[Section 29:143]**

[1]NAT'L COMM'N ON THE BP DEEPWATER HORIZON OIL SPILL AND OFFSHORE DRILLING, "DEEP WATER: THE GULF OIL DISASTER AND THE FUTURE OF OFFSHORE DRILLING" (2011), at 28–29.

[2]NAT'L COMM'N ON THE BP DEEPWATER HORIZON OIL SPILL AND OFFSHORE DRILLING, "DEEP WATER: THE GULF OIL DISASTER AND THE FUTURE OF OFFSHORE DRILLING" (2011), at 29. A drilling moratorium in the Gulf of Mexico was also temporarily imposed by DOI immediately after the *Deepwater Horizon* blowout, but the moratorium was enjoined by a federal court as violative of the Administrative Procedure Act. Hornbeck Offshore Services, L.L.C. v. Salazar, 696 F. Supp. 2d 627, 72 Env't. Rep. Cas. (BNA) 1601, 177 O.G.R. 399 (E.D. La. 2010).

[3]NAT'L COMM'N ON THE BP DEEPWATER HORIZON OIL SPILL AND OFFSHORE DRILLING, "DEEP WATER: THE GULF OIL DISASTER AND THE FUTURE OF OFFSHORE DRILLING" (2011), at 29.

[4]CITGO Asphalt Refining Company v. Frescati Shipping Company, Ltd., 140 S. Ct. 1081, 1085, 206 L. Ed. 2d 391 (2020).

refinery for failure to scan for and warn the *Athos I* about the presence of the anchor.[5] The dispute revealed another seam in OPA's ostensibly clear liability scheme.

- ***Cosco Busan.*** In late 2007, the cargo vessel *Cosco Busan* allided with the Bay Bridge, causing a discharge of over 1,000 barrels of bunker fuel into the San Francisco Bay. The owner of the *Cosco Busan* was the responsible party under OPA, but argued that it was not liable for cleanup and removal costs because the government had failed to comply with all of OPA's claim presentment requirements.[6] The Court concluded this argument was foreclosed by OPA's plain language, which provides that claims for removal "may be commenced . . . at any time."[7] This reading was found to further OPA's major purpose of allowing the government to "recover removal and cleanup costs [with] greater flexibility . . . than individuals seeking damages."[8] Because OPA is primarily concerned with expedient and economically efficient environmental remediation, mere technical deficiencies in claims presentment will not foreclose cost recovery.

### § 29:144 State law

Because OPA does not preempt state laws on oil spill liability, standards for liability and the types of parties than can be held liable vary widely from state to state. Some states impose strict liability on even "passive" parties to a discharge incident, such as holders of title to oil cargoes transported by vessel.[1] Any party with even limited interests in physical oil or means of transportation of oil should therefore carefully vet any applicable state laws to understand potential liability in the event of a release.

## H. TOXIC SUBSTANCES CONTROL ACT—APPLICATION TO OIL AND GAS OPERATIONS

### § 29:145 Introduction

This section discusses the application of the Toxic Substances Control Act (TSCA)[1] to oil and gas operations. Specifically, this chapter will briefly discuss the three TSCA Sections that are most applicable to the oil and gas industry: chemical data reporting under Section 8, pre-manufacturer notices and significant new use rules under Section 5, and testing requirements under Section 4. For each of these Sections, this part of the chapter analyzes the potential impacts on upstream oil and gas exploration and production, downstream processing and refining, and drilling and service providers.

Generally, upstream oil and gas production facilities will have few obligations under TSCA unless they are importing chemicals for use in fracking or enhanced oil recovery operations. Downstream processors and refineries are not exempt; they will have limited reporting obligations under Section 8 and are subject to Section 5

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[5] CITGO Asphalt Refining Company v. Frescati Shipping Company, Ltd., 140 S. Ct. 1081, 1087, 206 L. Ed. 2d 391 (2020).

[6] U.S. v. M/V COSCO BUSAN, 557 F. Supp. 2d 1058, 1059–60, 2008 A.M.C. 1360 (N.D. Cal. 2008).

[7] 33 U.S.C. § 2717(f)(2).

[8] U.S. v. M/V COSCO BUSAN, 557 F. Supp. 2d 1058, 1061, 2008 A.M.C. 1360 (N.D. Cal. 2008).

**[Section 29:144]**

[1] *See, e.g.,* Md. Envt'l Code § 4-401(j)(1)(i) (persons responsible for discharges include "[t]he owner of the discharged oil[.]").

**[Section 29:145]**

[1] 15 U.S.C. §§ 2601 et seq.

and Section 4 of TSCA. Well drilling and service providers may also be subject to TSCA if they manufacture or import chemicals. With the recent change in the presidential administration as of publication, there also exists the possibility that the use of fracking chemicals may come under greater scrutiny. This could lead to additional reporting or testing obligations and potential restrictions on the use of such chemicals.

## § 29:146 The Toxic Substances Control Act

Following World War II, commercial production of industrial chemicals remained largely unregulated despite having become pervasive in agriculture, manufacturing, mining, construction, and consumer products.[1] The first major piece of legislation regulating industrial chemicals was enacted by Congress in 1976 under the Toxic Substances Control Act.[2] The purpose of TSCA was to empower the Environmental Protection Agency (EPA) to evaluate the potential risks of new and existing chemicals and to find ways to prevent or reduce pollution caused by these chemicals before they can enter the environment.

Despite its substantial policy goals, the original TSCA was, for the most part, a chemical recording and notification act. Following its enactment, the EPA compiled an inventory of 62,000 industrial chemicals then in use. These chemicals, including many naturally occurring and petroleum stream chemicals discussed below, were grandfathered into commercial use and assumed to be safe.[3] However, the EPA's ability to assess the risks of these existing chemicals was limited. For example, in the first 15 years of its enactment, the agency was only able to review about 2% of the existing chemicals listed, despite the fact that the agency estimated that about 26% were potentially of concern based on their production volume and chemical properties.[4]

Due to these and other drawbacks, Congress enacted its first major revision to TSCA on June 22, 2016, under the Frank R. Lautenberg Chemical Safety for the 21st Century Act (the "Lautenberg Act."[5] The Lautenberg Act adopted several significant changes, including new obligations and deadlines imposed on the EPA, enhancements to the EPA's authority to regulate, and a clearer explanation of the process for the review and determination of risks.[6] One of the most substantial new obligations is a mandate to review the safety of existing chemicals.[7] Under the Lautenberg Act, chemicals are evaluated against a new risk-based safety standard to determine whether a chemical use poses an "unreasonable risk."[8] Given that there are over 83,000 chemicals currently listed in the TSCA inventory, this is a

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**[Section 29:146]**

[1] U.S. EPA, *About the TSCA Chemical Substance Inventory* (Sept. 24, 2019), https://www.epa.gov/tsca-inventory/about-tsca-chemical-substance-inventory.

[2] Toxic Substances Control Act, Pub. L No. 94-469, 90 Stat. 2003 (1976).

[3] Wilson & Schwarzman, *Toward a New U.S. Chemicals Policy: Rebuilding the Foundation to Advance New Science, Green Chemistry, and Environmental Health*, 117 ENV. HEALTH PERSP. 1202–1209 (Aug. 1, 2009).

[4] *See About the TSCA Chemical Substance Inventory*, *supra* note 2.

[5] Frank R. Lautenberg Chemical Safety for the 21st Century Act, Pub. L No. 114-182, 130 Stat. 448 (2016).

[6] Delong, *Toxic Results: The EPA's Power, Process, and Potential to Regulate Chemicals Under the Toxic Substances Control Act*, 68 DRAKE L. REV. 213, 219 (2020).

[7] Delong, *Toxic Results: The EPA's Power, Process, and Potential to Regulate Chemicals Under the Toxic Substances Control Act*, 68 DRAKE L. REV. 213, 219 (2020).

[8] U.S. EPA, *Summary of the Toxic Substances Control Act* (Sept. 9, 2020), https://www.epa.gov/laws-regulations/summary-toxic-substances-control-act.

considerable undertaking.[9]

## § 29:147 Chemical Data Reporting

Under Section 8, manufacturers and importers are required to provide the EPA with information on chemicals, currently listed on the TSCA inventory, that they manufacture domestically or import into the United States.[1] EPA has promulgated regulations to implement the reporting requirements.[2] This is commonly called the Chemical Data Reporting rule (CDR rule). Examples of required information includes: chemical or mixture identity, categories of use, quantity manufactured or processed, by-product description, health and environmental effects information, number of individuals exposed, and method(s) of disposal.[3] The EPA uses this data to help assess the potential human health and environmental impacts of these chemicals and makes the non-confidential business information it receives available to the public.[4] Generally, the EPA collects this information every four years from those manufacturers and importers who produce or import 25,000 lbs. or more of a chemical substance at a single site for a specific reporting year.[5] However, a lower threshold may apply for chemical substances that are the subject of certain TSCA actions, such as those mandated by TSCA sections 4, 5, or 6.[6]

## § 29:148 Application of CDR to Oil and Gas Exploration and Production Facilities

Under the CDR rule, certain categories of chemical substances—including polymers, microorganisms, naturally occurring chemical substances, and certain forms of natural gas and water—are fully exempt from the reporting requirements.[1] Therefore, oil and gas exploration and production companies generally do not have any obligations to report under the CDR rule unless they are importing chemical substances that are not fully exempt under 40 C.F.R. § 711.6.

Although oil and gas exploration and production facilities may not be subject to the regular reporting requirements under Section 8(a), these companies may still be subject to Section 8(e). Section 8(e) states that any person who "manufactures,

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[9]For more information on TSCA generally, *see* chapter 17 of this treatise.

**[Section 29:147]**

[1]15 U.S.C. § 2607.

[2]40 C.F.R. §§ 711 et seq. (2021).

[3]U.S. EPA, *Legislative and Regulatory Authority for Chemical Data Reporting* (Feb. 17, 2021), https://www.epa.gov/chemical-data-reporting/legislative-and-regulatory-authority-chemical-data-reporting#small.

[4]*See* U.S. EPA, *TSCA Chemical Data Reporting Fact Sheet: Chemical Substances which are the Subject of Certain TSCA Actions* available at https://www.epa.gov/sites/default/files/2015-03/documents/chemical_substances_which_are_the_subject_of_certain_tsca_actions.pdf.

[5]40 C.F.R.§ 711.15 (2021). Any person who must report under this part, as described in § 711.8, must submit the information described in this section for each chemical substance described in § 711.5 that the person manufactured (including imported) for commercial purposes in an amount of 25,000 lb. (11,340 kg) or more (or in an amount of 2,500 lb. (1,134 kg) or more for chemical substances subject to the rules, orders, or actions described in § 711.8(b)) at any one site during any calendar year since the last principal reporting year (e.g., for the 2020 submission period, consider calendar years 2016, 2017, 2018, and 2019, because 2015 was the last principal reporting year).

[6]40 C.F.R.§ 711.8(b) (2021).

**[Section 29:148]**

[1]40 C.F.R. § 711.6 (2021).

processes,[2] or distributes in commerce a chemical substance or mixture and who obtains information which reasonably supports the conclusion that such substance or mixture presents a substantial risk of injury to health or the environment shall immediately inform the Administrator of such information unless such person has actual knowledge that the Administrator has been adequately informed of such information."[3] This is unlikely to apply to naturally occurring substances produced from the well, but could apply to fracking chemicals or chemicals used in enhanced recovery operations. Further, this Section does *not* provide exemptions for small businesses, small production or importation volumes, or commercial activities such as manufacture for export only or research and development.[4]

## § 29:149 Application of CDR to Downstream Processors and Refiners

Under the CDR Rule, petroleum process streams are only partially exempt from reporting.[1] Therefore, downstream petroleum manufacturers and refiners are required to provide some information to the EPA under the CDR rule, such as a certification statement signed and dated by an authorized official of the submitter company, company and site information, and some chemical-specific information, if they manufacture or import such materials above the requisite thresholds.[2] Downstream processors and refiners are exempt from the requirement to provide chemical-specific information related to processing and use, including consumer and commercial use information and production volumes.[3] After considering the totality of information available regarding petroleum streams, including the chemical substance's chemical and physical properties or potential for persistence, bioaccumulation, health effects, environmental effects, and several other risk factors,[4] the EPA concluded that this chemical-specific information related to processing and use of petroleum is of "low current interest" and therefore, not necessary to report at this time.[5]

In light of the events at the time of TSCA's enactment, such as the 1973 oil crisis and ensuing enactment of Energy Policy and Conservation Act of 1975, the EPA's choice not to impose potentially burdensome reporting requirements on petroleum manufacturers that could have slowed petroleum production is understandable. However, with the adoption of the Lautenberg Act in 2016 and based on recent information regarding the link between petroleum use and climate change, some TSCA critics argue that these chemicals may pose a substantial risk of injury to health or the environment pursuant to Section 8(e). They maintain that the EPA should therefore reassess the petroleum stream exemption to reflect government policies on the reduction of greenhouse gas emissions.[6]

## § 29:150 Application of CDR to Well Drilling and Service Providers

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[2] A "processor" is someone who prepares a substance or mixture, after its manufacture, for distribution in commerce either (a) in the same form or physical state or in a different form or physical state, or (b) as part of an article containing the chemical substance or mixture. *See* 15 U.S.C. § 2602(13).

[3] 15 U.S.C. § 2607(e).

[4] U.S. EPA, *Reporting a TSCA Chemical Substantial Risk Notice* (Apr. 26, 2018), https://www.epa.gov/assessing-and-managing-chemicals-under-tsca/reporting-tsca-chemical-substantial-risk-notice.

**[Section 29:149]**

[1] 40 C.F.R. § 711.6(b)1 (2021).

[2] 40 C.F.R. § 711.15 (2021).

[3] 40 C.F.R. § 711.15(b)(4) (2021).

[4] 40 C.F.R. § 711.6 (b)2(ii) (2021).

[5] 40 C.F.R. § 711.6 (b)2(i).

[6] *Supra* note 7, at 232.

Well drilling and service providers that are not manufacturing or importing chemical substances will not have any reporting obligations under the CDR rule. However, if a well drilling company or service provider imports non-exempt chemical substances, such as hydraulic fracturing (a.k.a., "fracking") fluids, at or above the reporting threshold, they would have an obligation to report under the CDR rule.

## § 29:151 Pre-Manufacture Notices and Significant New Use Rules

For purposes of regulation under TSCA, if a chemical is listed on the TSCA inventory as described above, the substance is considered an "existing" chemical substance in commerce. Any chemical that is not on the inventory is considered a new chemical substance.[1] The purpose of Section 5 of TSCA is to help manage the potential risk to human health and the environment from these new chemicals. Section 5 functions as a gatekeeper that can identify potential conditions or restrictions, up to a complete ban on production, that should be placed on the use of a new chemical before it enters commerce.[2] Any person who intends to manufacture or import a new chemical substance for a non-exempt commercial purpose is required to submit a pre-manufacture notice (PMN) at least 90 days prior to the manufacture or import of the chemical.[3] PMN submissions must include all available data, pursuant to 40 CFR §§ 720.45 and 720.50, for consideration by EPA risk assessors, on the following: chemical identity; structure and formula process; diagram and description; production volume; byproducts and impurities; intended use; environmental release; disposal practices; human exposure; and existing available test data on the effect on human health or the environment.[4]

Additionally, Section 5 can regulate "new significant uses" of existing chemicals substances or mixtures. Significant New Use Rules (SNURs) can be used to require notice to EPA before chemical substances and mixtures are used in new ways that might create concerns.[5] Once the EPA determines that a use of a chemical substance is a significant new use, TSCA section 5(a)(1)(B) requires persons to submit a significant new use notice (SNUN) to the EPA at least 90 days before they manufacture or process the chemical substance for that use.[6] In determining whether to issue SNURs for particular chemicals, the EPA will consider all relevant factors, including those listed in TSCA section 5(a)(2): [p]rojected volume of manufacturing and processing of a chemical substance; [e]xtent to which a use changes the type or form of exposure of humans or the environment to a chemical substance; [e]xtent to which a use increases the magnitude and duration of exposure of humans or the environment to a chemical substance; [and] [r]easonably anticipated manner and methods of manufacturing, processing, distribution in commerce, and disposal of a

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**[Section 29:151]**

[1] U.S. EPA, *Basic Information for the Review of New Chemicals* (May 18, 2017), https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca/basic-information-review-new.

[2] U.S. EPA, *Basic Information for the Review of New Chemicals* (May 18, 2017), https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca/basic-information-review-new.

[3] U.S. EPA, *Basic Information for the Review of New Chemicals* (May 18, 2017), https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca/basic-information-review-new; 15 U.S.C. § 2604.

[4] U.S. EPA, *Filing a Pre-manufacture Notice with EPA* https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca/filing-pre-manufacture-notice-epa; 15 U.S.C. § 2604.

[5] U.S. EPA, Actions under TSCA 5 (Jan. 8, 2021), https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca/actions-under-tsca-section-5#SNURs.

[6] 15 U.S.C. § 2604(a)(1)(B)(i).

chemical substance."[7]

If the EPA determines that a new chemical or significant new use presents unreasonable risk of injury to health or the environment, the "EPA may: (1) limit the amount manufactured/processed/distributed in commerce or impose other restrictions on the substance via an immediately effective proposed rule under section 6 of TSCA; or (2) issue an order to prohibit or limit the manufacture, processing or distribution in commerce to take effect on the expiration of the applicable review period."

## § 29:152 Application of PMN and SNURs to Oil and Gas Exploration and Production Facilities

Oil and gas exploration and production facilities would typically not be subject to any PMN regulations. Naturally occurring chemical substances are automatically included in the TSCA chemical inventory.[1] Specifically included on the list are any chemical substances which are naturally occurring and: (1) which are (i) unprocessed or (ii) processed only by manual, mechanical, or gravitational means; by dissolution in water; by flotation; or by heating solely to remove water; or (2) which are extracted from air by any means, will automatically be included in the inventory under the category "Naturally Occurring Chemical Substances."[2] Examples of such substances include: raw agricultural commodities; water, air, natural gas, and crude oil; and rocks, ores, and minerals.[3] Similarly, it would be unlikely that the EPA would, considering the criteria listed above, issue a SNUR for any of these naturally occurring substances.

## § 29:153 Application of PMN and SNURs to Downstream Processors and Refiners

Downstream processors and refiners are subject to both PMNs and SNURS. In December of 2020, the EPA posted a Compliance Advisory entitled "*Applicability of the Toxic Substances Control Act to Chemicals made from Petroleum and Renewable Sources Used as Fuels and Fuel Additives and Distillates*."[1] The Compliance Advisory reaffirmed that chemical substances used as fuels, fuel additives, and distillates made from either petroleum or renewable sources are subject to the TSCA and anyone who plans to manufacture or import a chemical made from petroleum or renewable sources must comply with the statutory and regulatory new chemical requirements under TSCA Section 5.[2] Currently, there are about 142 "naphthas" and 178 "distillates" on the TSCA Inventory, and they are considered Unknown, Variable composition, Complex, or Biological (UVCB) substances.[3] The EPA clearly states that anyone who desires to manufacture or import a chemical that is not on the TSCA Inventory must submit a PMN. If a manufacturer is unsure whether

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[7] U.S. EPA, *Actions under TSCA Section 5* (Jan. 8, 2021), https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca/actions-under-tsca-section-5#SNURs.

**[Section 29:152]**

[1] 40 C.F.R. § 710.4 (2003).

[2] 40 C.F.R. § 710.4 (2003).

[3] 40 C.F.R. § 710.4 (2003).

**[Section 29:153]**

[1] U.S. EPA, *Applicability of the Toxic Substances Control Act to Chemicals made from Petroleum and Renewable Sources used as Fuels and Fuel Additives and Distillates* (Dec. 2020), https://www.epa.gov/sites/production/files/2020-12/documents/renewable_naphtha_compliance_advisory_web_v3_1.pdf.

[2] *Id.*

[3] *Id.*

their chemical is listed, they are encouraged to submit a Bona Fide Intent to Manufacture or Import Notice under 40 C.F.R. § 720.25. The EPA will consider the information submitted in a bona fide notice and will provide a determination on the TSCA Inventory status for the chemical substance.

A SNUN will be required at least 90 days before any person may manufacture or process a chemical substance subject to a SNUR. There are several existing and proposed SNURS that may apply to petroleum manufactures, such as those with NAICS codes 325 and 324110 (e.g., chemical manufacturing and petroleum refineries).[4] Manufacturers are encouraged to search their chemicals on the EPA's Substance Registry Services site to determine if any manufactured or imported chemical is subject to a SNUR, or any other TSCA actions.[5]

## § 29:154 Application of PMN and SNURs to Well Drilling and Service Providers

As discussed above, well drilling and service providers that do not manufacture or import chemicals will not be subject to TSCA. However, a well drilling or service provider who *is* manufacturing or importing chemicals would be subject to the same Section 5 requirements as other manufacturers or importers. As noted above, importers need to submit a PMN to the EPA if they intend to import an unlisted chemical, and they will need to submit a SNUN in the event they import a chemical subject to a SNUR.

Companies that manufacture or import hydraulic fracking fluids are also subject to the TSCA Section 5 requirements. The fracking fluid used to recover gas and oil from shale rock usually contains mostly water in addition to some chemical additives and proppants.[1] Different chemicals are added depending on the rock type and other specifics of the extraction site.[2] The EPA identified 1,084 chemicals that were reported to have been used in fracking fluids between 2005 and 2013. The EPA's analysis of FracFocus 1.0 data indicates that between 4 and 28 chemicals were used per well between January 2011 and February 2013 and that no single chemical was used in all wells.[3] As fracking companies continue to alter and refine the composition of their fracking fluids, the new chemicals added to these fluids are subject to TSCA Section 5. Additionally, many of the chemicals already used in this process have not been fully evaluated or tested, making it possible that the EPA could issue a SNUR if it determines that any new or increased use of these existing chemicals could pose a potential risk under the criteria listed above.[4]

## § 29:155 Chemical testing

Under Section 4 of TSCA, the EPA has authority to require chemical manufacturers, importers, or processors to test chemical substances and mixtures and report

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[4] *See,* for example, 85 Fed. Reg. 26419 (May 4, 2020); 84 Fed. Reg. 43266 (Aug. 20, 2019); 85 Fed. Reg. 45109 (July 27, 2020); 80 Fed. Reg. 2885 (Jan. 21, 2015); 84 Fed. Reg. 66591 (Dec. 5, 2019).

[5] *See* U.S. EPA, *Help with Chemical Data Reporting: How to Search for Chemicals Subject to TSCA Actions* (May 2020), https://www.epa.gov/chemical-data-reporting/help-chemical-data-reporting-how-search-chemicals-subject-certain-tsca.

**[Section 29:154]**

[1] U.S. EPA, ASSESSMENT OF THE POTENTIAL IMPACTS OF HYDRAULIC FRACTURING FOR OIL AND GAS ON DRINKING WATER RESOURCES (2015) (EPA/600/R-15/047) (External Review Draft).

[2] U.S. EPA, ASSESSMENT OF THE POTENTIAL IMPACTS OF HYDRAULIC FRACTURING FOR OIL AND GAS ON DRINKING WATER RESOURCES (2015) (EPA/600/R-15/047) (External Review Draft).

[3] U.S. EPA, ASSESSMENT OF THE POTENTIAL IMPACTS OF HYDRAULIC FRACTURING FOR OIL AND GAS ON DRINKING WATER RESOURCES (2015) (EPA/600/R-15/047) (External Review Draft).

[4] *Actions under TSCA Section 5*, *supra* note 31.

the results to the EPA.[1] The EPA can require testing on the health and environmental effects of a chemical if there is insufficient information and if the testing is relevant to make a determination of whether the substance would cause an "unreasonable risk of injury to health and the environment."[2] The EPA can also order testing to review notices, perform a risk evaluation, or to prioritize a chemical substance.[3]

Prior to the 2016 Lautenberg Act, the EPA's testing authority was limited and, absent an Enforceable Consent Agreement (as discussed below), could only be exercised through the passing of a formal rule with public notice and comment. The EPA had to show a more than theoretical probability of a hazard or significant exposure risk that poses an "unreasonable risk of injury."[4] This created a "catch-22" where the EPA had to prove the existence of a risk that it needed testing to assess the presence of.[5] Because of this high standard, very few chemicals were actually tested, creating a gap in knowledge about certain chemical risks.[6]

The amended rule gave the EPA broader authority to order the testing of substances without issuance of a formal rule. In order to compel testing, the EPA need only to: (1) identify the need for the information to be gleaned from testing; (2) describe how readily available information was used to inform the decision to require new information; and (3) where applicable, explain why the use of an order is warranted rather than a rule or consent agreement.[7] Testing must be conducted in a tiered fashion where the results of screening tests inform future tests.[8] Additionally, under Section 21, any person can petition to the EPA to initiate a proceeding for the issuance, amendment, or repeal a Section 4 rule.[9]

The EPA also has the option to enter into Enforceable Consent Agreements (ECAs).[10] With an ECA, the EPA works with members of the U.S. chemical industry who have volunteered to perform testing on certain chemicals.[11] ECAs are designed to provide the EPA with data identified as necessary to evaluate a particular chemical substance without the need for the EPA to first make the risk or exposure based findings for a TSCA Section 4 test rule, and without introducing delays inherent in the rulemaking process.[12] As of 2018, there were 52 substances being evaluated

**[Section 29:155]**

[1]15 U.S.C. § 2603(a); EPA may require "any person who manufactures or processes, or intends to manufacture or process" to develop information under this rule. 15 U.S.C. § 2603(b)(3)(C).

[2]15 U.S.C. § 2603(a)(1).

[3]15 U.S.C. § 2603(a)(2).

[4]Delong, *supra* note 7, at 217.

[5]Delong, *supra* note 7, at 218.

[6]Delong, *supra* note 7, at 218.

[7]15 U.S.C. § 2603(a)(3).

[8]15 U.S.C. § 2603(a)(4).

[9]15 U.S.C. § 2620. In addition to Section 4, Section 21 allows citizens to file petitions under Section 6 rules imposing regulatory controls on chemicals, Section 8 rules requiring information, Section 5(e) orders affecting new chemical substances, or Section 6(b)(2) orders affecting quality control procedures. 15 U.S.C. § 2620; *see* U.S. EPA, *TSCA Section 21* (Nov. 12, 2019), www.epa.gov/assessing-and-managing-chemicals-under-tsca/tsca-section-21.

[10]40 C.F.R. § 790 (2021); https://www.federalregister.gov/documents/2010/02/19/2010-3242/amendments-to-enforceable-consent-agreement-procedural-rules.

[11]U.S. EPA, *Data Development and Information Collection to Assess Risks* (Mar. 3, 2020), www.epa.gov/assessing-and-managing-chemicals-under-tsca.

[12]75 Fed. Reg. 56472 (Sep. 16, 2010), https://www.federalregister.gov/documents/2010/09/16/2010-23131/amendments-to-enforceable-consent-agreement-procedural-rules.

under ECAs.[13]

### § 29:156 Applicability of Testing Requirements to Oil and Gas Exploration and Production Facilities

Oil and gas exploration and production companies are technically subject to Section 4 of TSCA.[1] Unlike Section 8, there are no express exemptions under Section 4 for naturally occurring chemical substances, such as crude oil and natural gas.[2] Despite this, these naturally occurring chemical substances are extremely common in commerce and have generally be considered low-risk. It is unlikely that the EPA would determine the existence of a need to compel testing for crude oil and natural gas.

However, while traditional crude oil and gas production are unlikely to be subject to testing at this time, oil and gas producers that develop their own fracking fluids have been under particular scrutiny in recent years. For example, in August 2011, the environmental group Earthjustice petitioned EPA requesting that the EPA pursue regulation of chemicals used in hydraulic fracturing, including drilling muds and fracturing fluids, under both Section 4 and Section 8.[3] Specific to Section 4, the group asked the EPA to pursue a requirement for manufacturers and processors of fracturing fluids to identify all chemicals used and to conduct toxicity testing on those chemicals.[4] Earthjustice argued that the chemicals used in fracking may present an unreasonable risk of injury to health and the environment for several reasons.[5] The group also argued that the large volume of chemicals used in hydraulic fracturing of wells in the United States could result in substantial human exposure to the chemicals, as well as a substantial release of the chemicals into the environment.[6] In the group's view, testing was required to obtain sufficient data on the chemicals' effects because existing federal and state disclosure requirements were inadequate.[7]

In November 2011, the EPA denied the petitioners' request for adoption of a rule under Section 4, stating that the petition did not set forth facts sufficient to support the required findings under TSCA Section 4(a)(1)(A) or 4(a)(1)(B) for issuance of a test rule. The EPA concluded that Earthjustice did not demonstrate that the

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[13] U.S. EPA, *TSCA 4 ECA—TSCA Section 4 Enforceable Consent Agreements* (Jan. 23, 2021), https://sor.epa.gov/sor_internet/registry/substreg/searchandretrieve/searchbylist/search.do?search=&searchCriteria.substanceList=227&searchCriteria.substanceType=-1.

**[Section 29:156]**

[1] 15 U.S.C. § 2602(9) (the term "manufacture" means to produce or manufacture hazardous substance).

[2] *See* 15 U.S.C. § 2602(2).

[3] Maule et. al., *Disclosure of Hydraulic Fracturing Fluid Chemical Additives: Analysis of Regulations*, 23 New Solutions 167–87 (2013), https://journals.sagepub.com/doi/pdf/10.2190/NS.23.1.j.

[4] Citizen Petition under Toxic Substances Control Act Regarding the Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production, Earthjustice to Lisa P. Jackson, Admin. EPA (Aug. 4, 2011), https://earthjustice.org/sites/default/files/fracking_petition.pdf.

[5] Adam Vann et al., Cong. Rsch. Serv., R43152, Hydraulic Fracturing: Selected Legal Issues (Nov. 15, 2013), https://library.law.uiowa.edu; https://library.law.uiowa.edu/sites/library.law.uiowa.edu/files/R43152.pdf.

[6] Adam Vann et al., Cong. Rsch. Serv., R43152, Hydraulic Fracturing: Selected Legal Issues (Nov. 15, 2013), https://library.law.uiowa.edu; https://library.law.uiowa.edu/sites/library.law.uiowa.edu/files/R43152.pdf.

[7] Earthjustice and 114 other organizations. Letter from Deborah Goldberg, Earthjustice to Wendy Cleland-Hamnett, Director, Office of Pollution Prevention and Toxics. Re: Citizen Petition Under Toxic Substances Control Act Regarding the Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production, (Aug. 4, 2011), 78 Fed. Reg. 41768, 41771 (Jul. 11, 2013), http://www.epa.gov/oppt/chemtest/pubs/Section_21_Petition_on_Oil_Gas_Drilling_and_Fracking_Chemicals8.4.2011.pdf.

chemicals presented an "unreasonable risk of injury to human health or the environment."[8] Additionally, the group failed to identify an "exposure trigger" demonstrating that the chemical will be produced or released into the environment in substantial quantities.[9] The authors of *Disclosure of Hydraulic Fracturing Fluid Chemical Additives: Analysis of Regulations* pointed to the inherent tension that existed in the regulations before the adoption of the Lautenberg Act. While EPA was able to require testing if it found that insufficient data existed, often the agency still had to prove an "unreasonable risk" for the risk trigger and "substantial quantities" for the exposure trigger.[10] In short, without the necessary data, the agency could not properly assess a chemical's risks, and without an identifiable risk, the agency could not collect a chemical's data.

While Earthjustice's petition for Section 4 testing was not successful, the EPA's testing authority has been considerably expanded since 2011 under the Lautenberg Act. While hydraulic fracking fluids are not currently being considered for further testing, this expanded authority leaves open the possibility that similar substances may be tested in the future.

## § 29:157 Applicability of Testing Requirements to Downstream Processors and Refiners

Downstream processors and refiners are subject to the EPA's testing authority under Section 4. Again, there are no exemptions or partial exemptions under this rule for petroleum stream chemicals. Petroleum manufactures have previously been subject to both ECAs and, more recently, test orders.

For example, in January 2021, EPA ordered the testing of several chemicals involved in petrochemical manufacturing (1,2,2-Tricholorethane, 1,2-Dichloroethane) and petroleum products (p-Dichlorobenzene, o-Dichlorobenzene).[1] The evaluation process for these chemicals began in December 2019 as part of the second batch of chemicals ordered to undergo testing after the passage of the Lautenberg Act.[2] Prior to the issuance of the test orders for these chemicals, the EPA designated 20 high priority substances for risk evaluation based on factors such as hazard potential, persistence and bioaccumulation, and potential uses of the chemical.[3] The EPA then released draft scope of risk evaluations for 13 of the 20 high priority substances prior to initiating testing.[4] All steps in the testing order process provided the opportunity for public input through notice and comment procedures. Although the testing of these chemicals was ordered after prioritization and risk evaluation, the information provided by Section 4 may also be used as the basis for prioritization findings as well.[5]

Prior to these test orders, the EPA negotiated ECAs with gasoline manufactures

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[8] Maule, *supra* note 61.

[9] Maule, *supra* note 61.

[10] Maule, *supra* note 61.

**[Section 29:157]**

[1] U.S. EPA, *TSCA Section 4 Test Orders* (Feb. 23, 2021), https://www.epa.gov/assessing-and-managing-chemicals-under-tsca/tsca-section-4-test-orders.

[2] U.S. EPA, *Chemicals Undergoing Risk Evaluation under TSCA* (Feb. 17, 2021) https://www.epa.gov/assessing-and-managing-chemicals-under-tsca/chemicals-undergoing-risk-evaluation-under-tsca.

[3] 84 Fed. Reg. 44300 (Aug. 22, 2019), https://www.regulations.gov/document?D=EPA-HQ-OPPT-2018-0427-0009.

[4] *Draft Scopes of the Risk Evaluations to be Conducted for Thirteen Chemical Substances Under the Toxic Substances Control Act; Notice of Availability*, REGULATIONS.GOV (Apr. 8, 2020), https://www.regulations.gov/document?D=EPA-HQ-OPPT-2018-0427-0027.

[5] *See TSCA Section Test Orders, supra* note 69.

and processors for the development and submission of test data for methyl tertiary-butyl ether (MTBE), tertiary-amyl methyl ether (TAME) and the nine-carbon aromatic hydrocarbon fraction (C9 fraction) used in gasoline blending.[6] The EPA's choice to use ECAs for these petroleum additives instead of a formal test rule was controversial. In his article, *MTBE: A Precautionary Tale*, Tom McGarity describes the several "critical points" at which EPA or Congress could have avoided the regulatory pitfalls that lead to groundwater contamination from MTBE.[7] One of these critical points was EPA's decision to allow for industrial users of MTBE, rather than the manufacturers of the chemical, to conduct their own chemical testing. After more than a year of additional negotiations, the EPA published notice of a Consent Order to which the EPA and five major oil companies had agreed on.[8] The companies agreed to conduct several different types of tests to identify potential risk factors for human exposure.[9] However, despite the EPA's concerns regarding groundwater contamination, the companies were able to avoid any environmental testing, and conducted little testing regarding risks posed by ingestion, one of the most common ways humans would be exposed to MTBE in drinking water.[10] Ultimately, after conducting this limited testing on MTBE, and similar testing on TAME, and C-9 fraction, the EPA closed each project and determined to take no further action.[11]

## § 29:158 Applicability of Testing Requirements to Well Drillers and Service Providers

Finally, as with the Sections discussed above, Section 4 would not have any major implications for well drillers or service providers that do not manufacture or import chemicals in their operations. The Section 4 testing requirements apply only to parties that currently or intend to produce, process, import, or manufacture chemicals.[1] However, as noted above, service companies that import chemicals into the customs territory of the U.S. are subject to the same testing requirements as manufacturers, and these imported chemicals may be subject to testing.[2] Additionally, fracking companies that manufacturer or import chemicals may be subject to testing requirements.

## § 29:159 Conclusion

In total, oil and gas exploration and production operations have not typically been a high priority under TSCA. Most traditional oil and gas exploration and production operations are exempt from reporting under Section 8, and unlikely to be heavily

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[6] Wiseman, *Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas Production and the Need to Revisit Regulation*, 20 FORDHAM ENV'T L. REV. 115, 168 (2009).

[7] McGarity, *MTBE: A Precautionary Tale*, 28 HARV. ENV'T L. REV. 281, 299 (2004), https://harvardelr.com/wp-content.

[8] McGarity, *MTBE: A Precautionary Tale*, 28 HARV. ENV'T L. REV. 281, 299, 301 (2004).

[9] Id.

[10] Id.

[11] Swick et al., *Gasoline toxicology: Overview of regulatory and product stewardship programs*, 70 REGUL. TOXICOLOGY & PHARMACOLOGY S6 (Nov. 2014), https://reader.elsevier.com/reader/sd/pii.

**[Section 29:158]**

[1] U.S. EPA, *Data Development and Information Collection to Assess Risks* (Feb. 17, 2021), https://www.epa.gov/assessing-and-managing-chemicals-under-tsca/data-development-and-information-collection-assess-risks; *see also* 15 U.S.C. § 2602 ("manufacture" is defined as importing, producing, or manufacturing chemicals).

[2] *See* 15 U.S.C. §§ 2602 to 2603; https://www.federalregister.gov/documents/2021/01/11/2020-28585/fees-for-the-administration-of-the-toxic-substances-control-act-tsca.

impacted by PMN rules and SNURs under Section 5, and testing rules under Section 4. This is because naturally-occurring chemical substances are excluded from the reporting requirements and are generally well-known and extremely common in commerce. Downstream processors and refiners, on the other hand, have obligations under Section 8 and have historically been minimally impacted by PMN rules, SNURs, or testing requirements.

However, innovation in refinement processes may bring about the introduction of new chemicals that could be identified as higher risk and in need of further evaluation. Additionally, the EPA has more recently signaled through its December 2020 Compliance Advisory and January 2021 test orders that petroleum manufacturers may be under greater scrutiny in the future.

Finally, while many well drilling and field service providers are not regulated under TSCA because they do not manufacture or import any chemicals, those companies that import chemicals and companies that manufacture chemicals used for fracking are regulated and are subject to the reporting requirements under TSCA Section 8, the PMN requirements under TSCA Section 5 and possibly the testing requirements under TSCA Section 4. The manufacturing of fracking chemicals is likely one area that will be subject to much higher scrutiny under TSCA, especially under Sections 5 and 4.

## I. EMERGENCY PLANNING AND COMMUNITY RIGHT-TO-KNOW ACT

### § 29:160 Introduction

The Emergency Planning and Community Right-to-Know Act (EPCRA), passed by Congress on October 17, 1986, enables nimble community emergency response to chemical releases and promotes public disclosure of possible chemical hazards.[1] EPCRA ensures that communities and state governments work together to protect public health through a series of measures including: the preparation of chemical emergency response plans, required emergency notifications subsequent to release, the submission of Safety Data Sheets (SDSs) to state, local, and tribal officials, and annual reporting of toxic chemical release inventory forms—each of which are applicable in some fashion to oil and gas operations.[2]

EPCRA utilizes tiers of commissions and levels of reporting to ensure compliance and prompt response.[3] The pertinent parties are:

- State Emergency Response Commissions (SERCs)
- Local Emergency Planning Committees (LEPCs)
- Tribal Emergency Response Commissions (TERCs)
- Tribal Emergency Planning Committees (TEPCs)

The Governor and Chief Executive Officer of the tribe establish SERCs and TERCs respectively. The SERCs and TERCs in turn oversee LEPCs and TEPCs. LEPCs and TEPCs then develop emergency response plans, review them annually, and inform the public about chemicals in the community. As a practical matter, the

**[Section 29:160]**

[1] 42 U.S.C. §§ 11001 to 11005, 11021 to 11023, 11041 to 11050.

[2] The major EPCRA provisions include emergency planning (§§ 301–303), emergency release notification (§ 304), hazardous chemical storage reporting requirements (§§ 311-312), and toxic chemical release inventory (§ 313). The regulations implementing these provisions are codified in 40 C.F.R. §§ 350 to 372 (2021).

[3] *See* U.S. EPA, *Guide to the Emergency Planning and Community Right-to-Know Act*, *available at* https://www.epa.gov/sites/production/files/2020-10/documents/guide_to_epcra.pdf. (Last visited on June 29, 2021).

Environmental Protection Agency (EPA) is responsible for EPCRA regulation and oversight.

## § 29:161 Emergency Planning Notification (Section 302)

Section 302 requires facilities containing any Extremely Hazardous Substance (EHS) to develop an Emergency Response Plan, to be provided to the appropriate SERC and LEPC (or TERC and TEPC). Broadly, these plans contain information that help community officials react swiftly in the event of an accident.[1] The EPA maintains a list of EHSs and respective Threshold Planning Quantities (TPQs), based on acute toxicity in the event of an accidental release, above which facilities must provide these planning reports.[2] There are currently around 355 EHSs listed by the EPA.[3]

## § 29:162 Hazardous Substance Release Notification (Section 304)

Section 304 requires facilities to immediately report releases of EHSs or hazardous substances (HSs) listed under CERCLA regulations, that are equal to or in excess of the minimum Reportable Quantities (RQs) allowed, where such releases could result in exposure to people outside the boundary of the facility.[1] In addition to the 355 EHSs listed under EPCRA, there are over 800 HSs listed under CERCLA—a release of any one of these substances would trigger the need for an emergency release notification.

In 1990, the EPA revised the definition of "facility" to include "manmade structures as well as natural structures in which chemicals are purposefully placed or removed through human means such that it functions as a containment structure for human use."[2] This change expanded the confines of facilities to cover subsurface areas where there are subterranean operations. This is particularly applicable to upstream oil and gas operations engaged in exploration and production. By virtue of drilling, these operations extend their "facility," and the related release notification obligations, underground.

As an example, hydrogen sulfide can frequently be found in the ground where drilling for oil and gas. Because drilling operations risk releasing this gas, the subsurface area where drilling occurs falls within the definition of "facility."

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**[Section 29:161]**

[1] 40 C.F.R. § 355.20 (2021).

[2] 40 C.F.R. § 355, Apps. A (alphabetical order) and B (CAS number order). "TPQs are based on acute mammalian toxicity and potential for airborne dispersion and represent those quantities of substances that can cause significant harm should an accidental release occur."; U.S. EPA, *What is the relationship between reportable quantities (RQs) and threshold planning quantities (TPQs)*?, https://www.epa.gov/epcra/what-relationship-between-reportable-quantities-rqs-and-threshold-planning-quantities-tpqs (last visited June 29, 2021).

[3] 40 C.F.R. § 355, App. A.

**[Section 29:162]**

[1] 40 C.F.R. § 355 (2021) Apps. A (alphabetical order) and B (CAS number order). "The reportable quantity (RQ) that triggers emergency release notification (Section 304) was developed as a quantity that when released, poses potential threat to human health and the environment." U.S. EPA, *Emergency Planning and Community Right-to-Know Act Frequent Questions*, https://www.epa.gov/epcra/what-relationship-between-reportable-quantities-rqs-and-threshold-planning-quantities-tpqs (last visited June 29, 2021) (explaining the relationship between RQs and TPQs); As a practical matter the release notification requirement is in addition to and independent of the release notification requirements of Section 103 of CERCLA—releases at a facility that are not reportable under EPCRA Section 304 may still be reportable under CERCLA Section 103.

[2] 55 Fed. Reg. 30632, 30644 (July 26, 1990).

Hydrogen sulfide is an EHS,[3] meaning the quantity the facility generates must be included in TPQ determinations for Section 302 notifications. Further, as a result of drilling, any release of this hydrogen sulfide that affects persons off-site would also be subject to Section 304 reporting.

Oil and gas operations should be aware of one release notification distinction between EPCRA and CERCLA. Whereas petroleum, including crude oil or any fraction thereof, is excluded from the list of HSs under CERCLA,[4] no such "petroleum exclusion" exists under EPCRA.[5] Under CERCLA, petroleum contamination, and petroleum's constituent substances such as benzene, toluene, and xylene, do not need to be reported as long as the constituent substances do not exceed levels normally found in refined petroleum.[6] Under EPCRA however, if there is a petroleum release, and the constituent substances of that petroleum are EHSs or HSs that exceed the RQs, then that release would need to be reported.

The Fifth Circuit, in *Center for Biological Diversity, Inc. v. BP America Production Co.,* affirmed this distinction between CERCLA and EPCRA reporting for petroleum.[7] In response to the Deepwater Horizon oil spill, the Center for Biological Diversity brought suit against BP alleging, *inter alia*, current/continuing violations of CERCLA and EPCRA. The trial court dismissed the claims for lack of standing, mootness, and a failure to state a claim.[8] However, on appeal, the Fifth Circuit remanded the EPCRA claim for further proceedings to determine whether BP's EPCRA notifications were sufficient. In remanding, the court implicitly acknowledged the possibility that the petroleum exclusion does not extend to EPCRA, rather than affirming on the basis of failure to state a claim.

The petroleum exclusion under EPCRA was later formally acknowledged in comments to a proposed final rule regarding the exclusion of air emissions from animal waste at farms.[9] In this final rule, the EPA buttressed the rationale for excluding air emissions from animal waste by comparing to the petroleum exclusion. Although acknowledging that petroleum (including crude oil or any fraction thereof) is "expressly excluded from the definition of 'hazardous substance' in CERCLA," the EPA affirmatively stated that a release of petroleum containing an EHS is still subject to Section 304 reporting under EPCRA.[10]

## § 29:163 Hazardous Chemical Inventory Reporting

Under Section 311 and 312 of EPCRA, facilities that have SDSs for chemicals held above certain threshold quantities must submit copies of the SDSs to the SERC (or TERC), LEPC (or TEPC), and local fire department. The minimum thresh-

[3]40 C.F.R. § 355 (2021) Apps. A (alphabetical order) and B (CAS number order); 40 C.F.R. § 302.4 (2021).

[4]40 C.F.R. § 302.4 (2021).

[5]U.S. EPA, *Emergency Planning and Community Right-to-Know Act Frequent Questions*, https://www.epa.gov/epcra/does-cercla-petroleum-exclusion-apply-epcra-release-notifications (last visited June 29, 2021).

[6]CERCLA §§ 101(14), 104(a)(2).

[7]Center for Biological Diversity, Inc. v. BP America Production Co., 704 F.3d 413, 76 Env't. Rep. Cas. (BNA) 1017, 2013 A.M.C. 221 (5th Cir. 2013).

[8]Center for Biological Diversity, Inc. v. BP America Production Co., 704 F.3d 413, 418, 76 Env't. Rep. Cas. (BNA) 1017, 2013 A.M.C. 221 (5th Cir. 2013).

[9]Amendment to Emergency Release Notification Regulations on Reporting Exemption for Air Emissions From Animal Waste at Farms, Emergency Planning and Community Right-to-Know Act, 84 Fed. Reg. 27533, 27536 (June 13, 2019) (codified at 40 C.F.R. § 355 (2021)).

[10]Amendment to Emergency Release Notification Regulations on Reporting Exemption for Air Emissions From Animal Waste at Farms, Emergency Planning and Community Right-to-Know Act, 84 Fed. Reg. 27533, 27536 (June 13, 2019) (codified at 40 C.F.R. § 355 (2021)).

old for Section 311 and 312 reporting is the TPQ or 500 pounds, whichever is less, for EHSs. For all other hazardous substances, the reporting threshold level is 10,000 pounds.

Each facility must submit an individual report unless the facilities are adjacent and contiguous or are otherwise similar.[1] To be considered similar, facilities must have the "same EHSs and HSs on-site at any one time in similar amounts."[2] If similar, facilities can submit a single generic report applicable to all facilities as long as they meet statutory information requirements.[3] This is particularly applicable for oil drilling operations. While a single company might operate multiple wells across an oil field that accesses a single subsurface oil deposit, they are still considered separate facilities under EPCRA.[4] But because the oil wells in a single oil field are likely similar, generic reporting is a beneficial alternative for drilling operations hoping to avoid multiple filings.

As part of Section 311–312 reporting, the EPA made clear that facilities must aggregate EHSs for TPQ exceedance evaluation.[5] In response to a 1989 notice of proposed rulemaking, specific questions arose regarding the treatment of hazardous components in crude oil. The EPA responded that "[a]ny EHS component of crude oil must be aggregated unless the crude oil is reported as a mixture."[6] Where crude oil is reported as a mixture, instead of the aggregate of its component parts, all EHSs must still be evaluated across the facility to determine, whether in the aggregate, they exceed the TPQ. For example, if a facility has two vessels on site that each hold 10,000 pounds of crude oil containing three percent by weight hydrogen sulfide, that facility can choose to report that hydrogen sulfide, an EHS, in either of two ways. First, they can aggregate the amount across the two tanks and report only 600 pounds of hydrogen sulfide (10,000 lbs * 2 tanks * 3% H2S concentration). Or second, they can report 20,000 lbs of a mixture containing 3% H2S. And because this applies to all EHSs, oil and drilling facilities must be cognizant of all potential sources of EHSs; these include both produced sources, such as crude oil, as well as stored sources, such as the hydrofluoric acid commonly found in drilling fluid.

## § 29:164 Toxic Chemical Release Inventory

The Toxic Release Inventory (TRI), established under Section 313, is a database available to the public that details information about certain toxic chemicals released annually to air, water and land, or managed as waste by facilities throughout the United States.[1] Facilities are required to submit annual reports, by July 1 each year, that list toxic chemicals or chemical categories manufactured, processed, or used in the previous calendar year that exceed the reporting threshold as defined by EPA. The goal of TRI is to empower citizens, through information, to hold companies and local governments accountable for how toxic chemicals are

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**[Section 29:163]**

[1] 42 U.S.C. § 11049(4).

[2] U.S. EPA, *Generic 311/312 reporting for oil fields and wells*, https://www.epa.gov/epcra/generic-311312-reporting-oil-fields-or-wells (last visited June 29, 2021).

[3] U.S. EPA, *Generic 311/312 reporting for oil fields and wells*, https://www.epa.gov/epcra/generic-311312-reporting-oil-fields-or-wells (last visited June 29, 2021).

[4] *See* 42 U.S.C. § 11049(4).

[5] Community Right-to-Know Reporting Requirements, 55 Fed. Reg. 30632 (July 26, 1990).

[6] 55 Fed. Reg. 30641 (July 26, 1990).

**[Section 29:164]**

[1] U.S. EPA, *Toxic Release Inventory (TRI) Program*, https://www.epa.gov/toxics-release-inventory-tri-program/tri-data-and-tools (last visited June 29, 2021).

managed. While natural gas processing facilities are subject to Section 313, other oil and gas extraction operations—for example, other operations classified under SIC code 13—are exempt.[2]

### § 29:165 Transportation Exemptions

Both transportation of chemicals and storage of chemicals incident to transportation, including natural gas, such as that at warehouses and transfer facilities, are largely exempt from EPCRA's reporting requirements.[1] This extends to oil and gas transportation in pipelines.[2] There are two exceptions to this rule: (1) transporters are still required to follow the emergency notification of release provisions under Section 304;[3] and (2) hazardous chemicals must have active shipping papers and stored chemicals must still be "moving under active shipping papers and which have not reached the ultimate consignee."[4]

## J. IMPACTS TO WILDLIFE

### § 29:166 Generally

The law of oil and gas is closely intertwined with federal wildlife law. The oil and gas industry and the nation's wildlife both depend upon natural resource lands and, as a result, oil and gas developers and legal practitioners routinely interact with federal statutes designed to protect wildlife. The law in this area continues to evolve as policymakers, industry, conservation interests, and courts seek to balance the need for energy development with conservation values. Those themes are reflected throughout recent federal wildlife policies, including the greater sage-grouse conservation effort and the polar bear listing decision, both discussed further below.

This section summarizes three key federal wildlife statutes that oil and gas practitioners are likely to encounter: the Endangered Species Act, the Migratory Bird Treaty Act, and the Marine Mammal Protection Act. These statutes present potentially significant regulatory implications for individual oil and gas project proponents and the industry as a whole.

### § 29:167 Endangered Species Act

The cornerstone federal environmental law protecting wildlife and habitat is the Endangered Species Act of 1973 (ESA).[1] The oil and gas industry routinely encounters the ESA through two main entrance points. First, the expansive "take" prohibition in Section 9 of the ESA poses liability risk for many activities commonly associated with oil and gas exploration and development. Second, all federal agencies are obligated, under Section 7 of the ESA, to avoid actions that are likely to jeopardize the continued existence of any species protected under the ESA or adversely affect species' critical habitat. As a result, project proponents seeking federal approvals or permits or entering into federal contracts or leases may trigger

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[2] Addition of Natural Gas Processing Facilities to the Toxics Release Inventory, 82 Fed. Reg. 1651, 1653 (Jan. 6, 2017) (codified at 40 C.F.R. § 372 (2021)).

**[Section 29:165]**

[1] EPCRA § 327, 42 U.S.C. § 11047.

[2] Extremely Hazardous Substance List and Threshold Planning Quantities; Emergency Planning and Release Notification Requirements, 52 Fed. Reg. 13378 (Apr. 22, 1987) (codified at 40 C.F.R. § 355 (2021)).

[3] EPCRA § 304, 42 U.S.C.§ 11004(d).

[4] H.R. Rep. No. 99-962 (1986) (Committee of Conference). 99 CONG. CONF. H REP. 962, at 311.

**[Section 29:167]**

[1] 16 U.S.C. §§ 1531 to 1543.

additional regulatory requirements under Section 7.

The ESA's provisions apply to species that are "listed" through a federal rulemaking process as "endangered" or "threatened" pursuant to Section 4(a).[2] In conjunction with the listing process, the ESA also requires the federal government to designate "critical habitat" for each listed species "to the maximum extent prudent and determinable."[3]

Two federal agencies have primary responsibility to implement the ESA's provisions. The National Marine Fisheries Service (NMFS) has authority (delegated by the Secretary of Commerce) extending to most marine species and to anadromous species, such as salmon. The U.S. Fish and Wildlife Service (USFWS) has authority (delegated by the Secretary of the Interior) extending to all species not overseen by NMFS. The ESA refers to each Secretary as the "Secretary," and the two implementing agencies are colloquially referred to as the "Services."

As noted, two key provisions of the ESA most commonly affect individual oil and gas project proponents. First, the ESA's "take" prohibition in Section 9 prohibits any person—including any business entity—from "taking" an endangered species of fish or wildlife on public or private lands.[4] The "take" prohibition is expansive and imposes strict liability for both direct and indirect acts that injure or kill wildlife,[5] as well as acts that are "incidental to"—*i.e.*, not the purpose of—other lawful actions. The Services have authority to enforce the take prohibition through administrative

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[2] 16 U.S.C. § 1533(a). An "endangered" species is one that "is in danger of extinction throughout all or a significant portion of its range." 16 U.S.C. § 1532(6). A "threatened" species is one that "is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range." 16 U.S.C. § 1532(20).

[3] 16 U.S.C. § 1533(a)(3)(A). The term "critical habitat" refers to (1) specific areas within the geographical area occupied by the species at the time of listing, which contain physical or biological features essential to the conservation of the species and that may require special management considerations or protection, and (2) specific areas outside the species' geographical area at the time of listing that the Secretary determines to be "essential" for the species' conservation. 16 U.S.C. § 1532(5)(A). For further discussion of the ESA's listing and critical habitat designation processes, *see* Environmental Law Institute, Law of Environmental Protection, Spring 2021, Environmental Law Institute, §§ 21.9–21.22).

[4] 16 U.S.C. § 1538(a)(1)(B). Historically, the USFWS had presumptively extended the take prohibition to all threatened species as well, unless the Service had promulgated a "4(d) rule" specifying special management requirements for a particular threatened species. In 2019, the USFWS promulgated a new regulation reversing that presumption and providing that threatened species are *not* subject to the ESA's take prohibition unless either Service has promulgated a species-specific rule extending the take prohibition to that species. *See* U.S. Department of the Interior, Endangered and Threatened Wildlife and Plants; Regulations for Prohibitions to Threatened Wildlife and Plants, 84 Fed. Reg. 44753 (Aug. 27, 2019); 50 C.F.R. § 17.31 (2021). That approach was consistent with the approach that NMFS has historically taken to extend the take prohibition to threatened species on a species-specific basis. *See generally* 50 C.F.R. pt. 223, Subpart B ("Restrictions Applicable to Threatened Marine and Anadromous Species"). As of June 2021, the Biden Administration's USFWS had announced that it intended to reverse the Trump Administration's approach and reinstate the "blanket 4(d)" rule presumptively extending the take prohibition to all threatened species. *See* U.S. Fish and Wildlife Service, Endangered Species: ESA Implementation—Regulation Revisions, https://www.fws.gov/endangered/improving_ESA/regulation-revisions.html. For further discussion of this issue, refer to Law of Environmental Protection, Spring 2021, Environmental Law Institute, § 21.33.

[5] The ESA broadly defines "take" as "to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or to attempt to engage in any such conduct." 16 U.S.C. § 1532(19). The ESA's implementing regulations, in turn, define "harass" as any "intentional or negligent act or omission which creates the likelihood of injury to wildlife by annoying it to such an extent as to significantly disrupt normal behavioral patterns which include, but are not limited to, breeding, feeding, or sheltering." 50 C.F.R. §§ 17.3, 222.102 (2021). "Harm" is defined as "an act which actually kills or injures wildlife"; the term may include significant habitat modification or degradation that significantly impairs essential behavioral patterns, such as breeding, feeding, or sheltering. 50 C.F.R. §§ 17.3, 222.102 (2021); *see also* Law of Environmental Protection, Spring 2021, Environmental Law Institute, § 21.34.

and, in some cases, civil and criminal actions.[6] And, as further discussed below, the Services may also authorize "incidental," unintentional take under certain circumstances. In addition, the ESA's citizen suit provision enables private citizens to enforce the take prohibition in federal court.[7]

Second, Section 7 of the ESA requires that each federal agency "consult" with the relevant Service to ensure that any action authorized, funded, or carried out by the agency is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of any critical habitat of such species.[8] Oil and gas projects routinely trigger the consultation requirement through requests for federal agency permits or other authorizations, including but not limited to Federal Energy Regulatory Commission (FERC) approvals, oil and gas leases and rights-of-way on federal lands and the Outer Continental Shelf, and permits needed under the Clean Water Act, Clean Air Act, and other environmental statutes for oil and gas development and/or operations. Through the Section 7 consultation process, the Services may impose conditions on project operations to minimize impacts to ESA-listed species.[9] For that reason, the Services can play a key role in conditioning and minimizing the impacts of oil and gas projects or operations, even though the Services do not authorize the actual projects or operations. Further, federal agency actions triggering Section 7 are subject to judicial review in federal court under the Administrative Procedure Act (APA), as are the Services' consultation documents issued through the Section 7 process.[10] Therefore, the Section 7 process provides another litigation avenue for project opponents.

The ESA does provide a number of mechanisms for project proponents and operators to proactively limit their liability under the statute. Project proponents may enter into a variety of voluntary conservation agreements with the federal government. As one example, project proponents can prepare a "habitat conservation plan" and apply to the relevant Service for an "incidental take permit" under Section 10.[11] A "biological opinion" issued through the Section 7 process may also include an "incidental take statement" authorizing the activities that are the subject of the consultation, subject to terms and conditions imposed by the consulting Service.[12]

Because of the regulatory reach of both Section 9 and Section 7, a decision to list

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[6] *See* 16 U.S.C. § 1540.

[7] 16 U.S.C. § 1540(g); *see, e.g.*, In re Oil Spill by Oil Rig Deepwater Horizon, 792 F. Supp. 2d 926, 932, 74 Env't. Rep. Cas. (BNA) 1027 (E.D. La. 2011), aff'd in part, rev'd in part, 704 F.3d 413, 76 Env't. Rep. Cas. (BNA) 1017, 2013 A.M.C. 221 (5th Cir. 2013) (addressing environmental plaintiffs' Section 9 claims for injunctive relief against companies associated with the Deepwater Horizon oil spill), *aff'd in part, rev'd in part sub nom.* Center for Biological Diversity, Inc. v. BP America Production Co., 704 F.3d 413, 76 Env't. Rep. Cas. (BNA) 1017, 2013 A.M.C. 221 (5th Cir. 2013).

[8] 16 U.S.C. § 1536.

[9] *See* 16 U.S.C. § 1536(a).

[10] *See, e.g.*, Center for Biological Diversity v. Bernhardt, 982 F.3d 723 (9th Cir. 2020) (environmental groups challenged the Bureau of Ocean Energy Management's approval of an offshore oil drilling and production facility under the APA for noncompliance with Section 7 of the ESA); Defenders of Wildlife v. United States Department of the Interior, 931 F.3d 339 (4th Cir. 2019) (environmental groups challenged USFWS's "no jeopardy" conclusions under Section 7 in connection with FERC licensing for proposed natural gas pipeline construction project); Bennett v. Spear, 520 U.S. 154, 177–78, 117 S. Ct. 1154, 1168–69, 137 L. Ed. 2d 281, 44 Env't. Rep. Cas. (BNA) 1161, 27 Envtl. L. Rep. 20824 (1997) (holding that U.S. Fish and Wildlife Service's biological opinion was a final agency action subject to judicial review under the APA).

[11] 16 U.S.C. § 1539(a)(1)(B).

[12] 16 U.S.C. § 1536. For further discussion of these and related mechanisms, refer to Law of Environmental Protection, §§ 21:39–21:44.

a particular species as endangered or threatened may have significant implications for oil and gas interests. For example, the USFWS's final decision to list the polar bear as a threatened species in 2008 has resulted in extensive litigation in addition to material practical implications for oil and gas activities impacting polar bears. In 2005, motivated in large part by its opposition to oil and gas exploration and development in and offshore of Alaska, the Center for Biological Diversity (CBD) petitioned the Service to list the polar bear under the ESA, citing the projected loss of the bears' sea ice habitat resulting from the effects of global climate change.[13] The Service failed to act within certain statutory deadlines triggered by the petition, resulting in litigation filed by CBD and, ultimately, a court order directing the Service to issue a final listing decision by May 15, 2008.[14] The Service's final decision listing the polar bear as a threatened species,[15] as well as its accompanying 4(d) rule,[16] and subsequent critical habitat designation,[17] resulted in multiple litigation challenges, including opposition by the oil and gas industry.[18] Ultimately, the courts upheld the Service's listing decision, final 4(d) rule, and critical habitat designation, meaning that oil and gas activities with the potential to cause take of polar bears are subject to direct regulation under the ESA. The USFWS has since issued multiple biological opinions for oil and gas activities impacting polar bears, pursuant to Section 7 of the ESA, and those biological opinions have themselves resulted in additional litigation.[19]

In another significant example, the USFWS determined in 2010 that the greater sage-grouse warranted protection as a threatened species under the ESA but that higher-priority actions precluded listing at that time.[20] Because of the ESA's Section 7 consultation requirement, the decision to list sage-grouse would have had sweeping consequences for activities requiring federal leases or permits, including oil and gas exploration activities on millions of acres of public lands managed by the Bureau of Land Management (BLM) throughout the western United States. The Service's

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[13]*See* Center for Biological Diversity, Before the Secretary of the Interior: Petition to List the Polar Bear (*Ursus maritimus*) as a Threatened Species Under the Endangered Species Act (Feb. 16, 2005) 87–105, *available at* https://www.biologicaldiversity.org/species/mammals/polar_bear/pdfs/15976_7338.pdf.

[14]Center for Biological Diversity v. Kempthorne, 2008 WL 1902703 (N.D. Cal. 2008).

[15]U.S. Department of the Interior, Endangered and Threatened Wildlife and Plants; Determination of Threatened Status for the Polar Bear (Ursus maritimus) Throughout Its Range, 73 Fed. Reg. 28212 (May 15, 2008).

[16]As noted, a 4(d) rule is a special rule pertaining to a species listed as threatened under the ESA. Through a 4(d) rule, the relevant Service can customize prohibitions and regulate activities to provide for the conservation of the threatened species. After several years of litigation over the initial polar bear 4(d) rule, the USFWS issued the final polar bear 4(d) rule in 2013. *See* U.S. Department of the Interior, Endangered and Threatened Wildlife and Plants; Special Rule for the Polar Bear Under Section 4(d) of the Endangered Species Act, 78 Fed. Reg. 11766 (Feb. 20, 2013). The final 4(d) rule is intended to align management of the polar bear under the ESA with management provisions under the Marine Mammal Protection Act, discussed below. 78 Fed. Reg. 11768; *see also* Center for Biological Diversity v. Salazar, 695 F.3d 893, 910–11, 75 Env't. Rep. Cas. (BNA) 1919, 183 O.G.R. 92 (9th Cir. 2012) (discussing intersection between the ESA's and MMPA's management provisions for polar bears).

[17]*See* United States Department of the Interior, Endangered and Threatened Wildlife and Plants; Designation of Critical Habitat for the Polar Bear (Ursus maritimus) in the United States, 75 Fed. Reg. 76086 (Dec. 7, 2010); Alaska Oil and Gas Ass'n v. Jewell, 815 F.3d 544, 550, 82 Env't. Rep. Cas. (BNA) 1128 (9th Cir. 2016) (upholding critical habitat designation rule challenged by oil and gas trade associations, among other plaintiffs, as unjustifiably large).

[18]*See* In re Polar Bear Endangered Species Act Listing and Section 4(d) Rule Litigation—MDL No. 1993, 709 F.3d 1, 76 Env't. Rep. Cas. (BNA) 1057 (D.C. Cir. 2013) (upholding final listing rule).

[19]*See, e.g.*, Center for Biological Diversity v. Salazar, 695 F.3d 893, 75 Env't. Rep. Cas. (BNA) 1919, 183 O.G.R. 92 (9th Cir. 2012).

[20]U.S. Department of the Interior, Endangered and Threatened Wildlife and Plants; Determination for the Gunnison Sage-Grouse as a Threatened or Endangered Species, 75 Fed. Reg. 59804 (Sept. 28, 2010).

2010 decision led to litigation that ultimately resulted in the largest landscape-scale conservation planning effort in U.S. history between federal agencies, states, and private stakeholders to address threats to sage-grouse habitat without listing the species under the ESA.[21] The resulting conservation approach relies heavily on land management plans adopted by the BLM in coordination with state and local decision-makers, which prioritize public lands based on their relative value as sage-grouse habitat and limit development activities in priority sage-grouse habitat areas.[22] BLM's decisions to issue oil and gas leases on public lands pursuant to those management plans have been the subject of ongoing litigation,[23] and the sage-grouse's ultimate listing fate under the ESA remains to be seen.

## § 29:168 Migratory Bird Treaty Act

The Migratory Bird Treaty Act of 1918 (MBTA) is one of the oldest federal wildlife conservation statutes.[1] The MBTA's protections extend to nearly every bird species found in North America,[2] and, as a result, the statute has potentially far-reaching implications for oil and gas development projects across the country.[3] Like the ESA, the MBTA prohibits "take" of species protected by the Act. However, unlike the ESA, the MBTA does not include an express pathway to authorize incidental, unintentional take. For many oil and gas developers, that risk of liability under the MBTA may materially impact how a project is designed and implemented.

The MBTA's key section provides:

> Unless and except as permitted by regulations made [by the Secretary of the Interior], it shall be unlawful at any time, by any means or in any manner, to pursue, hunt, take, capture, kill, attempt to take, capture, or kill, possess, offer for sale, sell, offer to barter, barter, offer to purchase, purchase, deliver for shipment, ship, export, import, cause to be shipped, exported, or imported, deliver for transportation, transport or cause to be transported, carry or cause to be carried, or receive for shipment, transportation, carriage, or export, any migratory bird, any part, nest, or egg of any such bird, or any product, whether or not manufactured, which consists, or is composed in whole or part, of any such bird or any part, nest, or egg thereof, included in the terms of [various international conventions].[4]

The USFWS's definition of take under the MBTA does not include activities that "harm" or "harass" wildlife and is, therefore, narrower than under the ESA.[5] The MBTA also departs from the ESA in that it does not contain a citizen suit provision.

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[21] *See* U.S. Fish & Wildlife Service, *Greater Sage-Grouse, 2015 Not Warranted Finding Under the Endangered Species Act* (Sept. 2015), https://www.fws.gov/greaterSageGrouse/PDFs/GrSG_Finding_FINAL.pdf.

[22] *See* U.S. Department of the Interior, Bureau of Land Management, BLM Greater Sage-Grouse Plans, https://www.blm.gov/programs/fish-and-wildlife/sagegrouse/blm-sagegrouse-plans (last visited June 30, 2021).

[23] *See, e.g.*, Montana Wildlife Fed'n v. Bernhardt, CV-18-69-GF-BMM, Order, Dkt. 147 (D. Mont. May 22, 2020).

**[Section 29:168]**

[1] 16 U.S.C. §§ 703 to 712.

[2] *See* 50 C.F.R. § 10.13 (2021) ("List of Migratory Birds").

[3] In addition, the Bald and Golden Eagle Protection Act (BGEPA) prohibits the "take" of eagles and their parts, nests, or eggs, unless authorized by a permit issued by the USFWS. 16 U.S.C. § 668. Practitioners should be aware of the possible applicability of the BGEPA for oil and gas activities with the potential to impact eagles.

[4] 16 U.S.C. § 703(a).

[5] *See* 50 C.F.R. § 21.3 (2021).

As a result, the USFWS is the sole entity responsible for enforcing the Act.[6]

Under the MBTA, knowingly taking a protected bird with intent to sell, barter, or offer for sale or barter is a felony.[7] More importantly for oil and gas activities, the MBTA provides that "any person, association, partnership, or corporation" that violates the MBTA is guilty of a misdemeanor punishable by a fine of not more than $15,000, six months' imprisonment, or both.[8] Courts have split regarding whether the misdemeanor provision imposes strict liability on any activities that cause "take" of migratory birds or is limited to intentional or direct acts.[9]

The scope of the MBTA's take prohibition has specific relevance to the oil and gas industry. The penalty for violating the MBTA is criminal liability, and recent high-profile examples indicate that MBTA penalties can be a significant source of exposure for the industry. Criminal penalties under the MBTA were a major component of the settlement for the Deepwater Horizon oil spill of 2010, totaling $100 million.[10] However, more routine oil and gas exploration and development activities also have the potential to incidentally kill or harm birds, including via well drilling and pipeline construction in nesting areas. Unlike the ESA, the MBTA includes no express authority to permit incidental take of protected birds.[11] As of this writing, Incidental take permits are currently unavailable under the MBTA. Therefore, the only risk management option historically available to project proponents has been to design operations to minimize the risk of unpermitted incidental take to birds—for example, by scheduling pipeline construction to occur outside of the nesting season or by covering oil waste pits.

During the Obama Administration, the USFWS considered establishing an incidental take permitting program under the MBTA.[12] The agency ultimately abandoned that effort and, in the final days of the Obama Administration in January 2017, the Department of the Interior issued a Solicitor's Opinion affirming its strict liability interpretation of the MBTA. The Solicitor's Opinion concluded that "the MBTA's prohibitions on taking and killing migratory birds apply broadly to any activity, subject to the limits of proximate causation," including "direct incidental take."[13] Later that year, the Trump Administration issued a new Solicitor's Opinion (the "Trump M-Opinion") withdrawing and replacing the Obama Administration's previous opinion.[14] Contrary to the prior opinion, the Trump M-Opinion concluded that the MBTA does *not* prohibit the incidental take of MBTA-protected birds and instead "is a law limited . . . to affirmative and purposeful actions, such as hunting and poaching, that reduce migratory birds and their nests and eggs, by killing or

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[6] *See* 16 U.S.C. § 706.

[7] 16 U.S.C. § 707(b).

[8] 16 U.S.C. § 707(a).

[9] *Contrast* U.S. ex rel. Schumer v. Hughes Aircraft Co., 119 F.3d 796, 805 (9th Cir. 1997) (interpreting MBTA as strict liability statute) *and* U.S. v. Engler, 806 F.2d 425, 431, 21 Fed. R. Evid. Serv. 1398, 17 Envtl. L. Rep. 20334 (3d Cir. 1986) (same), *contrast with* U.S. v. Brigham Oil and Gas, L.P., 840 F. Supp. 2d 1202, 1213 (D.N.D. 2012) ("[I]t is highly unlikely that Congress ever intended to impose criminal liability on the acts or omissions of persons involved in lawful commercial activity which may indirectly cause the death of birds protected under the [MBTA].").

[10] *See* United States v. BP Exploration & Prod., Inc., No. 2:12-cr-00292-SSV-DEK, Judgment, Dkt. 66 (E.D. La. Jan. 29, 2013).

[11] *See* 16 U.S.C. §§ 703 to 712.

[12] *See* U.S. Department of the Interior, Migratory Bird Permits; Programmatic Environmental Impact Statement, 80 Fed. Reg. 30032 (May 26, 2015) (announcing notice of intent to prepare environmental impact statement evaluating the impacts of proposed rulemaking to regulate incidental take of migratory birds).

[13] U.S. Department of the Interior, Solicitor's Opinion M-37041 (Jan. 10, 2017).

[14] U.S. Department of the Interior, Solicitor's Opinion M-37050 (Dec. 22, 2017).

capturing, to human control."[15] The USFWS subsequently issued further guidance interpreting the Trump M-Opinion "to mean that the MBTA's prohibitions on take apply when the *purpose* of an action is to take migratory birds, their eggs, or their nests."[16] The scope of the MBTA's liability provisions and the availability of incidental take permits under the MBTA remain key issues for oil and gas practitioners and project proponents going forward. On January 7, 2021, the USFWS published a Final Rule clarifying that "[i]njury to or mortality of migratory birds that results from, but is not the purpose of, an action (*i.e.*, incidental taking or killing) is not prohibited by the Migratory Bird Treaty Act."[17] However, on March 8, 2021, the Biden Administration issued Memorandum M-37065 permanently revoking and withdrawing the Trump M-Opinion,[18] and on May 7, 2021, the Service published a notice proposing to revoke the Final Rule, previewing its legal interpretation that the MBTA prohibits incidental take.[19]

## § 29:169 Marine Mammal Protection Act

Offshore oil and gas developers will almost certainly encounter the Marine Mammal Protection Act of 1972 (MMPA).[1] The MMPA imposes a "moratorium on the taking and importation of marine mammals and marine mammal products."[2] The term "marine mammal" encompasses all marine mammals, including sea otters, manatees, walrus, dugongs, seals, whales, dolphins, and porpoises, and "any mammal" that "primarily inhabits the marine environment (such as the polar bear)."[3] The term "take" means "to harass, hunt, capture, collect, or kill . . . any marine mammal," or to attempt to engage in such conduct.[4] The term "harassment" means "any act of pursuit, torment, or annoyance" that (i) "has the potential to injure a marine mammal or marine mammal stock in the wild" (known as "Level A harassment") or (ii) "has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering" (known as "Level B harassment").[5] Thus, the definition of "take" under the MMPA is similar—but not identical to—the scope of "take" under the ESA.

The USFWS and NMFS are tasked with implementing the MMPA, with a jurisdictional division of species that mirrors that of the ESA.[6] Additionally, the Marine Mammal Commission, a three-member independent federal agency, provides

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[15]U.S. Department of the Interior, Solicitor's Opinion M-37050 (Dec. 22, 2017), at 41.

[16]U.S. Department of the Interior, Fish and Wildlife Service, *Guidance on the recent M-Opinion affecting the Migratory Bird Treaty Act* (Apr. 11, 2018) (emphasis in original).

[17]50 C.F.R. § 10.14 (2021); *see* U.S. Department of the Interior, Fish and Wildlife Service, Regulations Governing Take of Migratory Birds, 86 Fed. Reg. 1134 (Jan. 7, 2021).

[18]U.S. Department of the Interior, Office of the Solicitor, Memorandum M-37065 (March 8, 2021).

[19]U.S. Department of the Interior, Fish and Wildlife Service, *Regulations Governing Take of Migratory Birds; Proposed Rule*, 86 Fed. Reg. 24573 (May 7, 2021).

**[Section 29:169]**

[1]16 U.S.C. §§ 1361 to 1423h.

[2]16 U.S.C. § 1371(a).

[3]16 U.S.C. § 1362(6).

[4]50 C.F.R. § 18.3 (2021); 50 C.F.R. § 216.3 (2021).

[5]16 U.S.C. § 1362(18)(A); 50 C.F.R. § 216.3 (2021).

[6]16 U.S.C. § 1362(12)(A). NMFS is responsible for implementing the MMPA's provisions with respect to whales, dolphins, porpoises, and seals and sea lions. The USFWS has responsibility for all other marine mammals, including walrus, manatees, sea otters, and polar bears. 16 U.S.C. § 1362(12)(A).

policy and scientific oversight for activities under the MMPA.[7] Unlike the ESA, the MMPA does not contain a citizen suit enforcement provision. Therefore, the USFWS and NMFS are the entities that enforce the MMPA.[8]

The MMPA includes exceptions to the take prohibition. Key among them, Section 101(a)(5) of the act authorizes the Services to "issue permits which authorize the taking or importation of any marine mammal."[9] The Services issue two forms of incidental authorization.

First, the Services may issue an incidental take regulation (ITR) through formal rulemaking.[10] An ITR prescribes requirements to authorize the "incidental, but not intentional, taking . . . of small number of marine mammals" as the result of a "specified activity . . . within a specified geographical region," and is effective for up to five years.[11] Once an ITR has been established, an individual project proponent may apply for a Letter of Authorization (LOA) authorizing incidental take within the scope of the specific regulations. Second, the Services may issue an incidental harassment authorization (IHA), without undertaking a formal rulemaking process.[12] IHAs are project-specific authorizations that function like other types of incidental take authorizations. IHAs may authorize only take by harassment and are limited to a period of one year.[13] The key requirements for both ITRs and IHAs are that the permitted activity be a "specified activity" that occurs in a "specified geographic region," involve the taking of "small numbers" of a marine mammal species or population stock, have a "negligible impact" on such species or stock, and "not have an unmitigable adverse impact on the availability of such species or stock for taking for subsistence."[14]

Pursuant to Section 101(a)(5) of the MMPA, the Services have issued many incidental take authorizations for oil and gas activities.[15] For example, since the early 1990s, the oil and gas industry has routinely requested, and the USFWS has issued, ITRs applicable to oil and gas exploration, development, and production activities in the Beaufort and Chukchi Seas off the coast of Alaska.[16] Individual operators seek and are granted LOAs pursuant to those regulations identifying, among other things, monitoring and mitigation plans for impacts to polar bears and walrus.[17] Environmental advocacy groups have filed unsuccessful challenges to many of those regulations.[18] As another example, in 2021, NMFS issued the first-ever ITR addressing oil and gas exploratory activities in the Gulf of Mexico. The ITR, which became effective April 19, 2021, is the result of more than a decade of effort by the industry and is the most extensive ITR ever issued.[19] NMFS has also recently issued IHAs for oil and gas seismic survey activities in the Atlantic Ocean,

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[7] 16 U.S.C. § 1401.

[8] 16 U.S.C. § 1377.

[9] 16 U.S.C. § 1374(a).

[10] 16 U.S.C. § 1371(a)(5)(A).

[11] 16 U.S.C. § 1371(a)(5)(A)(i).

[12] 16 U.S.C. § 1371(a)(5)(D).

[13] 16 U.S.C. § 1371(a)(5)(D).

[14] 16 U.S.C. § 1371(a)(5)(A).

[15] 16 U.S.C. § 1371(a)(5)(A).

[16] *See* 50 C.F.R. Subpart J (2021).

[17] *See* 50 C.F.R. § 18.124 (2021).

[18] *See, e.g.*, Center for Biological Diversity v. Salazar, 695 F.3d 893, 75 Env't. Rep. Cas. (BNA) 1919, 183 O.G.R. 92 (9th Cir. 2012); Center For Biological Diversity v. Kempthorne, 588 F.3d 701, 69 Env't. Rep. Cas. (BNA) 1897, 174 O.G.R. 607 (9th Cir. 2009); Alaska Wilderness League v. Jewell, 99 F. Supp. 3d 112 (D.D.C. 2015).

[19] *See* Department of Commerce, National Oceanic and Atmospheric Administration, Taking and

which were challenged by environmental plaintiffs in federal court.[20] As these examples reflect, MMPA incidental take authorizations can be a significant source of litigation. Developing an early strategy to engage with the relevant Service and build a strong administrative record is essential.

## VIII. HEALTH AND SAFETY IN THE OILFIELD

### § 29:170 Generally

The federal agencies with primary oversight for health and safety issues related to industrial operations include the EPA, the Occupational Safety and Health Administration (OSHA), and the Pipeline and Hazardous Material Safety Administration (PHMSA). However, two of the most well-known industrial safety programs—EPA's Risk Management Plan (RMP) regime and OSHA's Process Safety Management of Highly Hazardous Chemicals (PSM) standard—generally do not apply to upstream oil and gas operations. In addition to these federal agencies, operations can also be regulated under state counterparts that have received delegation of workplace safety programs from OSHA and regulation of intrastate pipelines from PHMSA.

### § 29:171 U.S. Environmental Protection Agency

EPA's RMP regulations are focused on reducing and responding to offsite health and safety impacts from releases. Facility-specific RMPs evaluate worst-case scenarios and outline release prevention and emergency planning considerations. RMPs for regulated facilities are also publicly available and facilities are required to hold a public meeting after any RMP reportable accident with a known offsite impact. EPA's RMP regulations require coordination with local emergency planning organizations—including scheduled emergency response exercises—to ensure an effective response in the event of a release.[1]

As discussed in Section 29:135, EPA's RMP regulations require facilities with more than a threshold quantity of a regulated substance to develop an RMP. These regulated substances are divided between two categories—regulated toxic substances and regulated flammable substances. Threshold quantities for regulated toxic substances varies depending on the substance, but all flammable substances are subject to a 10,000 pound threshold.[2] If a facility has a covered process that involves 10,000 pounds or more of a listed flammable substance, it must comply with RMP requirements. However, EPA's regulations provide several exemptions to the calculation of the 10,000 threshold, including an exemption for "naturally occurring hydrocarbon mixtures."[3] This includes "any combination of the following: condensate, crude oil, field gas, and produced water."[4]

Based on the exclusion for naturally occurring hydrocarbon mixes, most upstream oil and gas operations are exempt from compliance with EPA's RMP regulations.

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Importing Marine Mammals; Taking Marine Mammals Incidental to Geophysical Surveys Related to Oil and Gas Activities in the Gulf of Mexico, 86 Fed. Reg. 5322 (Jan. 19, 2021).

[20]*See, e.g.*, S.C. Coastal Conservation League v. Ross, Case No. 18-cv-03326 (D.S.C.). This litigation has since been dismissed without prejudice, in light of the expiration of the challenged IHAs in 2020. *See* S.C. Coastal Conservation League v. Ross, Case No. 18-cv-03326 (D.S.C.), Order, Dkt. 463 (Oct. 6, 2020).

**[Section 29:171]**

[1]*See* 40 C.F.R. §§ 68.93 to 68.96 (2021).

[2]*See* 40 C.F.R. § 68.130 (2021).

[3]40 C.F.R. § 68.115(b)(2)(iii) (2021).

[4]40 C.F.R. § 68.115(b)(2)(iii) (2021).

Typically, EPA's RMP regulations are a larger concern for downstream operations (e.g., refineries), where threshold levels of flammable substances are more likely to be met. However, even if a facility is not subject to the RMP regulations based on operation of a process meeting or exceeding threshold quantities, EPA may seek to enforce for noncompliance with the general duty clause.[5]

## § 29:172 U.S. Occupational Safety and Health Administration

In contrast to EPA's RMP regulations, which focus on offsite impacts, the U.S. Occupational Safety and Health Administration's (OSHA's) regulations focus on worker health and safety within the fence line. One of OSHA's flagship regulations is the PSM standard, which applies to processes involving a chemical at or above a listed threshold quantity, or flammable substances with a threshold of 10,000 pounds.[1] The PSM standard includes 14 elements, covering among other things: employee involvement, process safety information, process hazard analyses, operating procedures, training mechanical integrity, management of change, and emergency preparedness.[2]

Like EPA's RMP program, OSHA's PSM standard excludes certain oil and gas activities. In contrast to EPA's exclusion based on determination of threshold quantities, OSHA's regulations explicitly exclude "oil or gas well drilling or servicing operations" from applicability of the PSM standard.[3] OSHA has evaluated this exemption and the potential extension of PSM applicability to oil and gas production facilities several times over the years. In 2000, OSHA issued a stay on enforcement of the PSM standard at oil and gas production facilities.[4] However, OSHA continues to enforce the PSM standard for natural gas processing.[5]

Even when the PSM standard does not apply, operators are required to comply with standards for general industry (e.g., requirements for personal protective equipment, environmental controls, and materials handling). In addition, the Occupational Safety and Health Act of 1970 establishes a general duty for each employer to "furnish to each of his employees employment and a place of employment which are free from recognized hazards that are causing or are likely to cause death or serious physical harm to his employees."[6] OSHA uses this general duty clause when it identifies a hazard that is not otherwise addressed by a specific OSHA standard. As with the EPA RMP general duty clause, OSHA commonly ap-

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[5] EPA's guidance on implementing the general duty clause states that "EPA has jurisdiction to implement and enforce the general duty clause through Sections 113 and 114 of the Clean Air Act at any facility where extremely hazardous substances are present." *See* EPA, *Guidance for Implementation of the General Duty Clause Clean Air Act Section 112(r)(1)*, at 10 (May 2000), https://www.epa.gov/sites/production/files/documents/gendutyclause-rpt.pdf. In addition, EPA issued recent guidance to "[r]emind upstream (exploration and production) oil and gas facility owners and operators of public safety hazards associated with their facilities, and their obligations under the Clean Air Act general duty clause." *See* EPA, *Safety Alert Public Safety at Oil and Gas Upstream Facilities*, at 1 (March 2021), https://www.epa.gov/sites/production/files/2021-03/documents/safety_alert_for_oil_and_gas_storage_3-18-21.pdf.

**[Section 29:172]**

[1] *See* 29 C.F.R. § 1910.119 (2021).

[2] 29 C.F.R. § 1910.119 (2021).

[3] 29 C.F.R. § 1910.119 (a)(2)(ii) (2021).

[4] OSHA, *Standard Interpretation: Production facilities that recover natural gas liquids may have enforceable PSM-covered processes,* December 19, 2018, https://www.osha.gov/laws-regs/standardinterpretations/2018-12-19 (last visited June 29, 2021).

[5] OSHA, *Standard Interpretation: Production facilities that recover natural gas liquids may have enforceable PSM-covered processes,* December 19, 2018, https://www.osha.gov/laws-regs/standardinterpretations/2018-12-19 (last visited June 29, 2021).

[6] 29 U.S.C. § 654(a)(1).

plies the general duty clause in enforcement actions following an incident.

## § 29:173 Pipeline and Hazardous Materials Safety Administration

PHMSA, within the U.S. Department of Transportation, develops and enforces regulations applicable to interstate pipelines, covering gathering, transmission, and distribution systems. PHMSA's regulations for oil and gas pipelines set minimum safety requirements, including requirements concerning design, construction, testing, and operation standards.

A key aspect of PHMSA's regulation of oil and gas pipelines is the requirement for operators to establish and implement integrity management programs. These integrity management programs apply to those pipelines where a leak of failure could impact a high consequence area (certain areas with high populations or potential impacts on waterways or drinking water or ecological resources).[1] Integrity management programs must meet a suite of requirements associated with periodic testing/ integrity assessments (e.g., in-line inspection tools, pressure tests, or similar approaches) and the repair of any identified integrity concerns.[2]

## § 29:174 EPA

In keeping with the cooperative federalism framework of the CAA, while EPA is the primary regulatory authority for accidental releases pursuant to its RMP program, states may also receive delegated authority to implement and enforce a state program comparable to EPA's RMP program.[1] As with other CAA delegation standards, the state must establish standards at least as stringent as the federal requirements, though states may also set different or more stringent requirements or procedures.[2] Currently, nine states have received delegation from EPA to implement and enforce the RMP program.[3] The EPA remains the primary regulator in those states that have not received delegation.

## § 29:175 OSHA

Although OSHA establishes federal minimum standards, the Occupational Safety and Health Act allows states to assume responsibility for development and enforcement of occupational safety and health standards. States may receive delegation from OSHA if they establish a plan that imposes standards that are "at least as effective in providing safe and healthful employment" as OSHA's standards.[1] OSHA must review and approve the plan before the state can take delegation.[2] Currently, 22 states have received OSHA approval for their state plans covering private sector

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**[Section 29:173]**

[1] *See* 49 C.F.R. §§ 195.452, 192.911 (2021).

[2] 49 C.F.R. §§ 195.452, 192.911 (2021).

**[Section 29:174]**

[1] 42 U.S.C. § 7412(l).

[2] 42 U.S.C. § 7412(l).

[3] U.S. EPA, *States with authority to implement/enforced the risk management program rule*, https://www.epa.gov/rmp/states-authority-implement-enforce-risk-management-program-rule (last visited June 29, 2021).

**[Section 29:175]**

[1] 29 U.S.C. § 667(c).

[2] 29 U.S.C. § 667(c).

workers.[3] Delegated states may impose their own additional requirements, procedures, and penalty calculations. States also have the flexibility to impose stricter requirements than the federal minimum. OSHA continues to enforce federal requirements in states without an approved state plan.

### § 29:176 PHMSA

While PHMSA regulates *inter* state pipelines, states may take responsibility for promulgating and enforcing standards applicable to *intra*state pipelines. Every state—except Hawaii and Alaska—has entered a form of certification or agreement with PHMSA to take authority for at least certain aspects of the pipeline safety program.[1] As with the other programs that involve cooperative federalism, states may adopt more stringent regulations for pipeline safety, provided they continue to meet federal minimum standards. For example, a 2013 study by the National Association of Pipeline Safety Representatives noted that as of the date of the report "[t]here are at least 1,361 state regulatory administrative rules, legislative provisions and state agency orders that address pipeline safety requirements exceeding the federal pipeline safety code. This demonstrates that the majority of state pipeline safety programs are actively and constantly pursuing pipeline safety at a level responsive to local conditions."[2]

Those states that do not establish their own programs are subject to PHMSA's federal standards and PHMSA enforcement actions. In addition, although the majority of states have primary jurisdiction over intrastate pipelines through these agreements with PHMSA, interstate pipelines remain subject to PHMSA's jurisdiction. States may inspect pipelines on PHMSA's behalf, but PHMSA remains responsible for ensuring compliance and commencing enforcement actions.[3]

## IX. REGULATION OF REFINING AND MARKETING (THE "DOWNSTREAM" SECTOR)

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[3] *See* OSHA, *State Plan Frequently Asked Questions,* https://www.osha.gov/stateplans/faqs (last visited June 29, 2021).

**[Section 29:176]**

[1] National Association of Pipeline Safety Representatives, Executive Summary Compendium of State Pipeline Safety Requirements & Initiatives Compared to Code of Federal Regulations, 3 (September 18, 2013).

[2] 49 C.F.R. §§ 195.452, 192.911 (2021).

[3] National Association of Pipeline Safety Representatives, *Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety compared to Code of Federal Regulations*, 10 (September 9, 2013).


Source: U.S. Farm Security Administration; Photograph: Marion Post Wolcott (Barnsdall refinery in Wichita, Kansas) (Oct. 1941), Library of Congress call number: LC-USF34-059840-D [P&P] LOT 117.

### § 29:177 History and Overview of Petroleum Refining

On the receiving end of the transportation (midstream) sector of the oil and gas industry lies the downstream sector, consisting of the functions of petroleum refining and marketing. Petroleum refineries perform a simple function in society—they convert crude oil and liquids into a myriad of petroleum-based fuels and other products that people use every day. How refineries *perform* this function is, in contrast, technically and legally complex. This section and those that follow provide a brief background into the history, technical operation, and federal environmental regulation of petroleum refining and marketing in the United States.

Petroleum refining techniques were practiced as far back as the early first century in China, but the advent of modern commercial refining happened in late nineteenth century, following the discovery of oil in Titusville, Pennsylvania in 1859. The development of modern refining was driven by technological changes, both on the supply side by improved refining techniques and on the demand side by innovations requiring new fuels and refined products.

Initially, crude oil was refined to produce kerosene—a relatively heavy fraction of oil—to compete with whale oil as an illumination product. Generally considered a waste byproduct, gasoline—a lighter fraction of oil—was allowed to evaporate or was dumped into pits or nearby streams for disposal.[1] Early refining techniques for separating heavy from light fractions to render these products were highly inefficient. The method of separation used today, fractional distillation, did not come into widespread use in the United States until the 1920s, when alcohol distillers looking for work in the wake of Prohibition brought the technology to their new jobs

**[Section 29:177]**

[1] WILLIAM L. LEFFLER, PETROLEUM REFINING IN NONTECHNICAL LANGUAGE 1 (4th ed. 2008).

in the refining industry.[2]

Meanwhile, the invention of the internal combustion engine and the widespread adoption of automobiles amplified demand for gasoline. Fractional distillation alone could not produce enough gasoline to satisfy demand, necessitating the advent in the early 1900s of cracking technology to cook heavier fractions until they "crack" into lighter ones like gasoline. Over the ensuing decades, increasing demand for ever-lighter and more-efficient fuels led to the emergence of the techniques of catalysis and catalytic cracking in the 1930s and 1940s, and hydrocracking and reforming processes in the 1950s, which define modern refining.[3]

On the strength of demand for refined products, oil refineries proliferated through the first half of the twentieth century. By the 1970s, however, concerns over air emissions from the burning of refined fuels and their additives—in particular, lead—ushered in federal environmental regulation of the refining industry.[4] As regulation increased, the number of operating refineries decreased. From 1982 to 1994, the number of U.S. refineries fell by around 71%.[5] Small independent refineries constituted the bulk of the closures. In large part, the attrition owes to the difficulty in constructing new ones; the newest refinery with significant downstream capacity came online in 1977.[6] Environmental permitting and compliance costs contribute substantially to the already enormous capital investment and working capital requirements for constructing and operating a refinery, creating a barrier to entry that did not exist before the 1970s.[7] Additionally, some environmental regulations, such as federal and state fuel standards, have a direct impact on the value of refined products,[8] and therefore on refineries' profit margins. While difficult to predict, current efforts to increase regulation of greenhouse gas emissions from both the upstream industry and downstream sources of power generation, as well as fluctuating demand for refined products in the United States and abroad, may accelerate the trend of refinery closures in the coming decade. Notwithstanding the challenges, however, refineries may remain profitable enterprises, so long as there remains a margin between the cost of crude oil inputs and the composite value of the refined products.[9]

While the number of operable petroleum refineries has fallen, overall capacity has been creeping up, indicating the increase in efficiency achieved in recent decades. As of January 1, 2020, there were only 135 operable petroleum refineries in the United States, but refining capacity (referred to as "distillation capacity") reached an all-time high of 19 million barrels per day.[10] As depicted in the below map, these refineries are concentrated on the Texas and Louisiana shores of the Gulf of Mexico and other coastal locales where there is ready access to shipping lanes for refined products.

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[2] WILLIAM L. LEFFLER, PETROLEUM REFINING IN NONTECHNICAL LANGUAGE 1 (4th ed. 2008).

[3] WILLIAM L. LEFFLER, PETROLEUM REFINING IN NONTECHNICAL LANGUAGE 3 (4th ed. 2008).

[4] WILLIAM L. LEFFLER, PETROLEUM REFINING IN NONTECHNICAL LANGUAGE 3 (4th ed. 2008).

[5] Saha & Gamkar, *Evaluating the Distribution of Environmental and Social Impacts of the Petroleum Refining Industry: A Preliminary Analysis*, 18 LBJ J. OF PUB. AFFS. 38, 39 (2005).

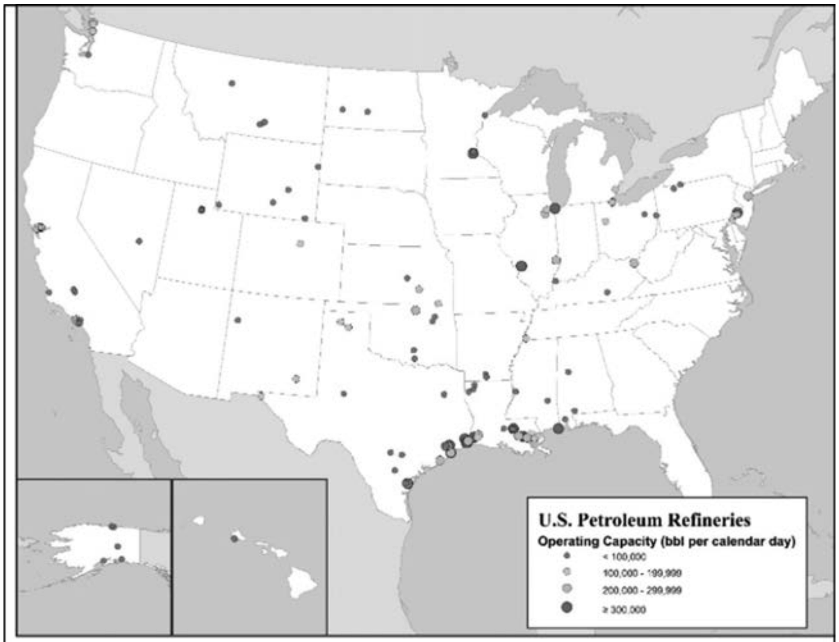
[6] U.S. EIA, *When Was the Last Refinery Built in the United States?*, https://www.eia.gov/tools/faqs/faq.php?id=29&t=6 (last visited June 24, 2021).

[7] MOHAMED A. FAHIM, TAHER A. ALSAHHAF & AMAL ELKILANI, FUNDAMENTALS OF PETROLEUM REFINING 404–05 (2010).

[8] *See* Chapter 12 of this treatise (for a discussion of the fuel regulation program under the CAA and state boutique fuel requirements).

[9] FAHIM ET AL., *supra* note 7, at 408.

[10] U.S. EIA, *supra* note 6.




| Operating Capacity (barrels per calendar day) | Number of EIA Refineries Included in the Category | Total Refinery Atmospheric Crude Distillation Capacity (barrels per calendar day) |
|---|---|---|
| <100,000 | 67 | 3,050,000 |
| 100,000-199,999 | 31 | 4,680,000 |
| 200,000-299,999 | 20 | 4,880,000 |
| ≥300,000 | 14 | 5,960,000 |
| **Total** | **132[a]** | **18,600,000** |

Note: Capacity values are rounded to three significant figures.
a - The EPA's profile references individual refineries by NPDES ID, in some cases these refineries may be listed as two separate refineries in EIA (e.g., an East and West) or some refineries may not have reported production for 2018 or have closed since the population was developed in 2015.

**Figure 4-1. Map of United States Petroleum Refineries**

Source: U.S. EPA, DETAILED STUDY OF THE PETROLEUM REFINING CATEGORY—2019 REPORT 4-2 (2019).

Under the Defense Production Act of 1950, the nation's refineries are aggregated into five geographical districts, called Petroleum Administration for Defense Districts (PADDs), for purpose of federal regulation.[11] The federal government uses PADDs to collect, organize, and report data on petroleum refining through the Energy Information Administration (EIA) and to organize regulatory standards under various environmental statutes and regulations. PADDs are depicted in the following map:

[11] 50 U.S.C. §§ 4501 to 68.


U.S. Energy Info. Admin. (Feb. 7, 2012), https://www.eia.gov/todayinenergy/detail.php?id=4890.

## § 29:178 Overview of the Marketing Sector

Together with the refining sector, petroleum marketing makes up the "downstream" side of the oil and gas industry. Marketing refers to the wholesale and retail distribution of refined products to end users in industry, business, and government sectors, as well as to individual consumers.[1] A significant portion of the marketing sector involves retail sale of fuels to consumers through gasoline stations. In addition to gasoline stations, refined products are marketed directly to factories, power plants, and transportation-related industries.[2] The significant diversity of marketing operations is revealed by the number of individual North American Industry Classification categories that fall within the downstream industry—nine in total, excluding petroleum refining.[3] These categories include fuel dealers; bulk stations and terminals; manufacturers of petroleum products, asphalt products, lubricating oil and grease; and wholesalers of manufactured products.

Though not nearly as heavily regulated as the petroleum refining sector, petroleum marketing operations are subject to significant environmental regulation. This regulation focuses primarily on (1) the operation, monitoring, and remediation of leaking underground storage tanks used at gasoline stations,[4] and (2) the types of fuels that may be sold in any particular region of the country, under the Clean Air Act's (CAA's) fuel standards programs and related state boutique fuel requirements.[5] These fuel standards influence both the refining and marketing sectors by limiting the regions where certain fuels may be marketed.[6]

## § 29:179 Technical Operation of Refineries

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**[Section 29:178]**

[1] LIBRARY OF CONGRESS, DOWNSTREAM: REFINING AND MARKETING, https://guides.loc.gov/oil-and-gas-industry/downstream (last visited June 24, 2021).

[2] LIBRARY OF CONGRESS, DOWNSTREAM: REFINING AND MARKETING, https://guides.loc.gov/oil-and-gas-industry/downstream (last visited June 24, 2021).

[3] LIBRARY OF CONGRESS, DOWNSTREAM: REFINING AND MARKETING, https://guides.loc.gov/oil-and-gas-industry/downstream (last visited June 24, 2021).

[4] *See* §§ 14:74 to 14:84 of this treatise.

[5] *See also* Chapter 12 of this treatise.

[6] Pierce Jr., *Environmental Regulation, Energy, and Market Entry*, 15 DUKE ENVTL. L. & POL'Y F.

To comprehend the environmental regulation of refineries, it is helpful to understand some basic aspects of refinery operations. Modern petroleum refineries are massive and complex. Refineries operate around the clock, typically 24 hours per day and 365 days per year. They employ large numbers of employees and occupy massive tracts of land.[1] The details of a refinery's operations are determined by the kind and quality of crude oil and other liquids available as inputs,[2] as well as the prevailing market demand for particular refined products.[3] Because the refining process generally decreases the density of crude oil, a standard 42-gallon (U.S.) barrel of crude oil yields about 45 gallons of refined petroleum products.[4] These refined products include, in various proportions, gasoline, distillate (diesel and heating oil), kerosene, jet fuel, and many other residual products and products used in petrochemical manufacturing.

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167, 170 (2005).

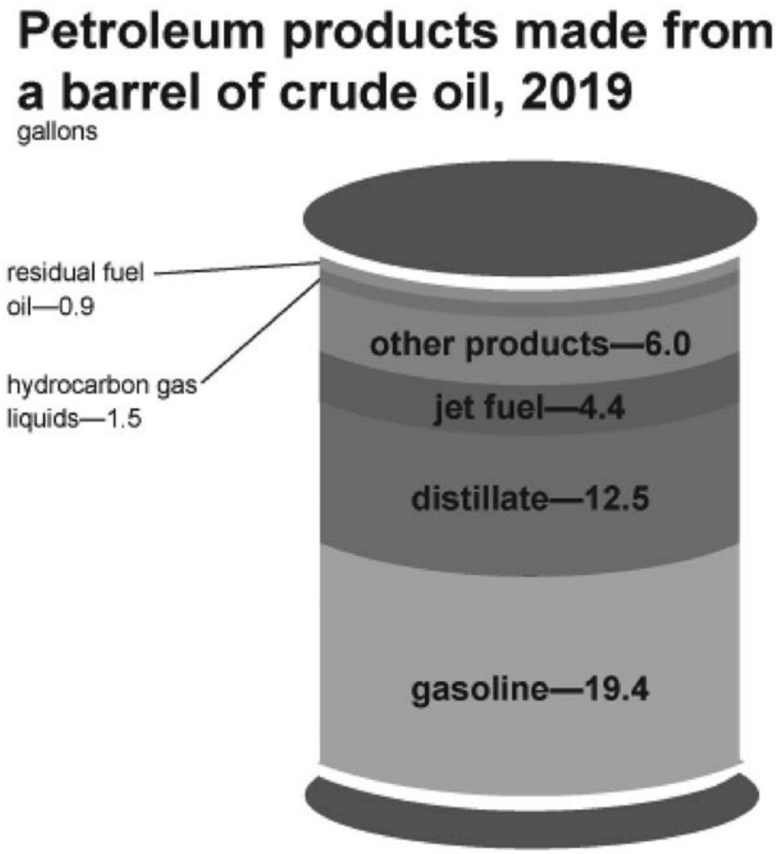
**[Section 29:179]**

[1]U.S. EIA, *Oil and Petroleum Products Explained: Basics*, https://www.eia.gov/energyexplained/oil-and-petroleum-products/refining-crude-oil.php (last visited June 24, 2021).

[2]U.S. EIA, *Oil and Petroleum Products Explained: Refining Crude Oil*, https://www.eia.gov/energyexplained/oil-and-petroleum-products/refining-crude-oil-inputs-and-outputs.php (last visited June 24, 2021).

[3]U.S. EIA, *supra* note 6.

[4]U.S. EIA, *supra* note 6.




Note: A 42-gallon (U.S.) barrel of crude oil yields about 45 gallons of petroleum products because of refinery processing gain. The sum of the product amounts in the image may not equal 45 because of independent rounding.

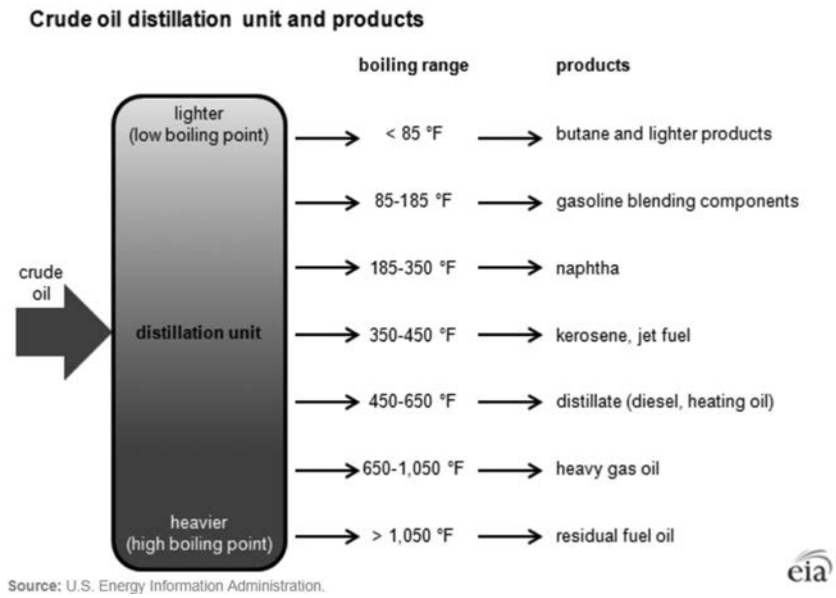
Source: U.S. Energy Information Administration, *Petroleum Supply Monthly*, April 2020, preliminary data

A bit of background into the chemistry of petroleum refining is also helpful. Crude oil refining proceeds in three basic sequential steps: (1) separation; (2) conversion; and (3) treatment.

Step 1: Separation. The first step is intended to break the crude oil into its component fractions to derive valuable products from each fraction. In the physical separation process, crude oil is first "desalted" by running it through hot furnaces to remove certain solids. The resulting fluids are discharged into atmospheric distillation units where they are introduced to super-heated steam.[5] Inside the distillation units, the liquids and vapors separate according to their various boiling points into petroleum components called "fractions." Light fractions rise to the top of the distillation tower and heavier fractions remain on the bottom.[6] As the following graphic illustrates, light fractions include gasoline, medium fractions include kerosene and jet fuel, and heavy fractions include residual fuel oils and heavy gas oils.

[5]Fahim et al., *supra* note 7, at 1–3.

[6]U.S. EIA, *supra* note 6.




At most modern refineries, the heaviest fractions (bottoms) are then introduced to a vacuum distillation tower where additional products are obtained.[7] Unlike *atmospheric* distillation, *vacuum* distillation towers operate below atmospheric pressure.[8] This is necessary because, at atmospheric pressure, heavy fractions cannot be heated to the needed temperatures without thermally cracking and degrading the oil. At the lower pressures present in vacuum distillation units, the boiling point of bottoms is low enough that lighter products can be obtained without cracking.

Step 2: Conversion. In this step, heavy fractions are processed into lighter products of higher economic value, like high-octane gasoline, jet fuel, and diesel fuel. Unlike in the separation stage, conversion typically employs chemical processes, often using catalysts, to break down the molecular structure of heavy fractions to create new petroleum products. The processes of "cracking," "coking," and "visbreaking" break large petroleum molecules into smaller ones. Cracking is the most commonly employed. It uses heat, pressure, and sometimes catalyst (cat-cracking) or hydrogen (hydrocracking) to break apart (crack) large petroleum molecules into smaller ones. Hydrocracking is an important source of diesel and jet fuels.[9] The primary source of gasoline is fluid catalytic cracking (FCC), which employs a fluid catalyst and heat in the cracking process.[10] Coking is a mode of thermal cracking in which residue from vacuum distillation is heated in a furnace and flashed into large drums where coke is then deposited on the walls. Coking produces gases, gasoline, and gas oils.[11] Visbreaking is another thermal cracking process used to break the high viscosity of heavy fractions.[12]

Other conversion processes create useful products by rearranging, rather than breaking down, the molecular structures of fractions. "Polymerization" and "alkyla-

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[7] FAHIM ET AL., *supra* note 7, at 1.

[8] U.S. EIA, *Vacuum Distillation Is a Key Part of the Petroleum Refining Process*, https://www.eia.gov/todayinenergy/detail.php?id=9130 (last visited June 24, 2021).

[9] U.S. EIA, *Hydrocracking Is an Important Source of Diesel and Jet Fuel*, https://www.eia.gov/todayinenergy/detail.php?id=9650 (last visited June 24, 2021).

[10] FAHIM ET AL., *supra* note 7, at 3.

[11] FAHIM ET AL., *supra* note 7, at 4.

[12] FAHIM ET AL., *supra* note 7, at 4.

tion" processes are like cracking in reverse; they combine small petroleum molecules into larger ones. Similarly, "isomerization" and "reforming" processes rearrange petroleum molecules to produce high-value products.[13]

Step 3: Treatment. The final step in the process is treatment. Here, technicians combine a variety of streams from the conversion process to blend fuels with varying octane levels, vapor pressure ratings, and other special considerations dictated by market demand and federal and state regulation.[14] The finished products are typically stored in large above-ground tanks in a tank farm on or near the premises of the refinery until they are transported to market by pipeline, rail, marine vessel, or truck.

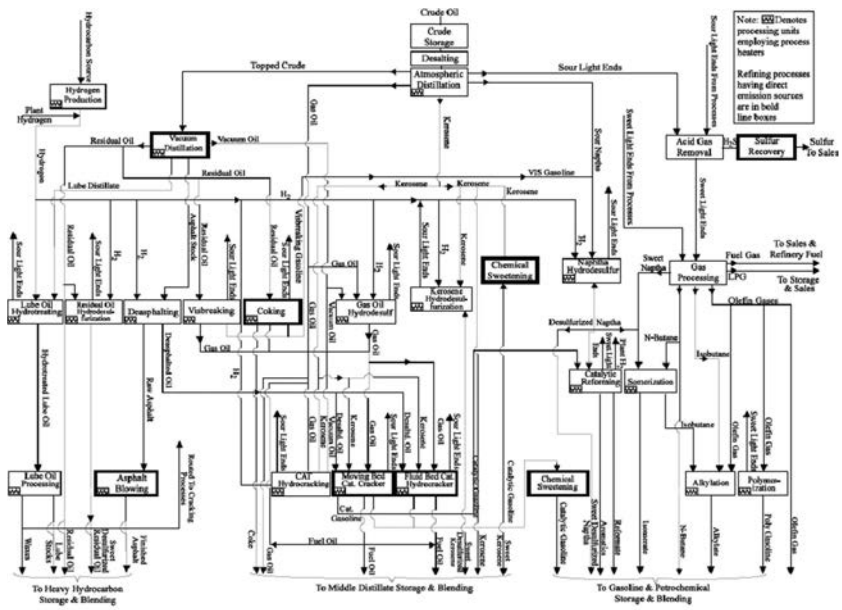


Figure 5.1-1. Schematic of integrated petroleum refinery.

I EPA, COMPILATION OF AIR POLLUTANT EMISSIONS FACTORS-42, Figure 5.1-1 (5th ed. 1995).

## § 29:180 Types and Sources of Pollution from Refineries

As described above, the refining process involves a complicated, technical, and multi-layered manufacturing procedure to develop many of the products we continue to rely on nationwide, from gasoline to diesel to petrochemical feedstocks. The process can also produce multiple kinds of waste and pollution. Broadly, refining processes generate three categories of waste: air emissions, solid waste and sludge, and polluted wastewater. Air emissions may be further subdivided into point source emissions, which are emitted from stacks, vents, and flares and are relatively easy to monitor and control, and non-point (or fugitive) emissions, which leak from valves, flanges, pumps, tanks, and the like and are more difficult to monitor and control.[1] Air emissions include greenhouse gasses (GHGs), volatile organic compounds (VOCs), all the criteria pollutants defined under the CAA—carbon monoxide, ground-level ozone, lead, nitrogen oxides, particulate matter, and sulfur

[13] FAHIM ET AL., *supra* note 7, at 3–4; U.S. EIA, *supra* note 6.

[14] FAHIM ET AL., *supra* note 7, at 3–4; U.S. EIA, *supra* note 6.

**[Section 29:180]**

[1] FAHIM ET AL., *supra* note 7, at 427.

dioxide—and numerous air toxins such as the so-called BTEX compounds of benzene, toluene, ethylbenzene and xylene.[2] During the separation process, the desalter emits hydrogen sulfide to the atmosphere and produces large volumes of "wash water" that contain chlorides, sulfides, ammonia, hydrocarbons, and suspended solids.[3] Distillation produces emissions of hydrocarbons (which contain VOCs) and hydrogen sulfide, as well as wastewater containing hydrocarbons and a number of chemicals, such as antifoam and corrosion additives.[4] The conversion process may be the greatest source of pollution. Catalytic cracking can cause air emissions of carbon monoxide, sulfur dioxide, nitrogen oxides, hydrogen sulfide, particulates, hydrocarbons, benzene, ammonia, and aldehydes.[5] The primary point sources for air emissions from the coking process are furnace stacks and flares, where off gas is rejected from the coking unit and combusted. Coking emissions can include hydrogen sulfide, carbon monoxide, in addition to hydrocarbons and VOCs.[6] Coking also uses large volumes of water as a coolant and to clean coking drums. While much of this water is recycled through the system, resulting wastewater may contain pollutants such as oil, sulfides, ammonia, and phenol.[7] Steam boilers, process furnaces, process heaters, and engines to run compressors, which are used throughout the refining process, may emit carbon monoxide, sulfur oxides, nitrogen oxides, and hydrocarbons.[8] In transportation and marketing operations downstream of the refining process, air emissions result from evaporation of vapors from refined products. Evaporative losses occur from large storage tanks; during loading into rail cars, tank trucks, and marine vessels; while products are stored in underground storage tanks at fuel stations (breathing losses); and during fueling of vehicles.[9]

## § 29:181 Regulation of Air Emissions: Greenhouse Gas Emissions Reporting Program

The following sections survey the major federal environmental laws that pertain to each of the above-described categories of waste generated by the refining process: air emissions, water discharges, and solid and hazardous wastes. This survey begins with regulation of air emissions under the federal Clean Air Act (CAA), and, specifically, with a relatively recent program for the regulation of GHG emissions.

In 2008, Congress appropriated money for the U.S. Environmental Protection Agency (EPA) to use its authority under the CAA to "require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States," including the downstream sector of the oil and gas industry.[1] The resulting regulations impose extensive monitoring, reporting, and recordkeeping requirements on petroleum refineries,[2] as well as suppliers of petroleum products (defined as refineries and importers and exporters of petroleum products

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[2] FAHIM ET AL., *supra* note 7, at 427; I U.S. EPA, COMPILATION OF AIR POLLUTANT EMISSIONS FACTORS-42, ch. 5.1 tbl. 1 (5th ed. 1995).

[3] FAHIM ET AL., *supra* note 7, at 423.

[4] FAHIM ET AL., *supra* note 7, at 424.

[5] FAHIM ET AL., *supra* note 7, at 424–25; I U.S. EPA, *supra* note 33, ch. 5.1 tbl. 1.

[6] FAHIM ET AL., *supra* note 7, at 424–25.

[7] FAHIM ET AL., *supra* note 7, at 424–25.

[8] I U.S. EPA, *supra* note 33, ch. 5.1 tbl. 1.

[9] I U.S. EPA, *supra* note 33, ch. 5.1 tbl. 2-1.

**[Section 29:181]**

[1] 74 Fed. Reg. 56259, 56264 (Oct. 30, 2009) (citing H.R. 2764, FY 2008 Omnibus Appropriations Bill; Pub L. 110-161; 121 Stat. 2128).

[2] 40 C.F.R. §§ 98.250 to 98.258 (2021).

and natural gas liquids)[3] that emit certain GHGs above applicable annual thresholds.[4] Annual GHG reports must be submitted to EPA no later than March 31 of each calendar year for GHG emissions produced in the previous calendar year.[5]

### § 29:182 Regulation of Air Emissions: New Source Review

One of the most significant sources of pollution regulation of petroleum refineries is the CAA's new source review (NSR) program, which requires facility operators to obtain a preconstruction permit before constructing a new source or a major modification of an existing source.[1] The key question for owners and operators of refineries under this program is whether a proposed modification to the refinery will constitute a "major modification." NSR was enacted in 1977, after all the significant United States refineries had already been constructed. This means that, to trigger the stringent requirements of the program, an refinery must undertake a "major modification."[2] Refineries are highly motivated to characterize any modifications as not major, as non-major modifications trigger only the laxer requirements of Minor NSR. A modification is "major" if it would cause a net increase in the source's actual emissions or its potential to emit (PTE) in excess of thresholds set for various pollutants by regulation,[3] or if the modification occurs within 10 kilometers of a designated Class I area (a wilderness area, for example) and the increased emissions would increase the 24-hour average concentration of any regulated pollutant in the ambient air by at least one microgram per cubic meter.[4] For a new petroleum refinery to qualify as a "major stationary source" and trigger major NSR, it must emit 100 tons per year (tpy) or more of any criteria pollutant (including fugitive emissions). As a practical matter, virtually any significant new refinery would exceed this threshold.[5] Alternatively, if a new refinery were to voluntarily accept federally enforceable limits on its emissions to keep the emissions below the major source threshold, it may avoid major NSR requirements as a "synthetic minor source."[6]

### § 29:183 Regulation of Air Emissions: New Source Performance Standards

In addition to the preconstruction permitting programs under NSR, the CAA imposes emissions standards for criteria pollutants on designated industrial or source categories of new sources under the new source performance standards (NSPS) program.[1] Sources subject to NSPS requirements must install best demonstrated technology (BDT), which refers to the best system of emission reductions that EPA determines has been adequately demonstrated, considering the costs of achieving such emission reductions, any non-air quality health and environmental

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[3] 40 C.F.R. §§ 98.390 to 98.398 (2021).

[4] 40 C.F.R. § 98.2 (2021).

[5] 40 C.F.R. § 98.3(b) (2021).

**[Section 29:182]**

[1] The NSR program is discussed in Chapter 12 of this treatise.

[2] Note, however, that existing refineries located in nonattainment regions are subject to RACT requirements under NA NSR.

[3] 40 C.F.R. § 51.166(b)(23)(i) (2021).

[4] 40 C.F.R. § 51.166(b)(23)(iii) (2021).

[5] 40 C.F.R. § 52.21(b)(1)(i)(a) (2021).

[6] 40 C.F.R. § 49.167 (2021).

**[Section 29:183]**

[1] CAA §§ 111(d) & 129, 42 U.S.C. §§ 7411(d) & 7601. For discussion of NSPS, *see* Chapter 12 of this treatise.

impact, and energy requirements.[2]

Petroleum refineries are subject to a number of NSPS, each promulgated at 40 C.F.R. Part 60. Subpart J imposes NSPS for fluid catalytic cracking units, fluid coking units, delayed coking units, fuel gas combustion devices, and sulfur recovery plants that were constructed as part of a petroleum refinery between 1970 and 2007.[3] Subpart J sets emissions control standards for particulate matter, carbon monoxide, and sulfur oxides,[4] and imposes monitoring, testing, and reporting and recordkeeping requirements.[5] Subpart Ja imposes NSPS for the same category of refinery components (i.e. parts within refineries) that are constructed, reconstructed, or modified after May 14, 2007.[6] The emissions limitations of Subpart Ja cover the same criteria pollutants as Subpart J plus sulfur dioxides.[7] Subpart Ja also requires operators of flares to develop and implement a written flare management plan,[8] and imposes operational requirements for certain flares, combustion devices, and sulfur recovery plants.[9] It further permits owners and operators to apply to EPA for permission to employ alternative means of emission limitation.[10] Like Subpart J, Ja requires performance testing, leak monitoring, reporting, and recordkeeping.[11]

Subparts GGG and GGGa establish standards of performance for equipment leaks of VOCs at petroleum refineries constructed, reconstructed, or modified between January 1983 and November 2006 and after November 2006, respectively.[12] Similarly, Subpart QQQ sets standards of performance for VOCs emissions from petroleum refinery wastewater systems,[13] including drain systems, oil-water separators, and aggregate facilities.[14] In addition to the performance standards, the regulations require leak repairs, monitoring, reporting, recordkeeping,[15] and permit alternative standards of emission limitation.[16]

The petroleum marketing sector is also subject to NSPS. Subpart XX establishes VOCs emissions from new and modified bulk gasoline terminals. A bulk gasoline terminal transfers and stores gasoline and other refined petroleum products as they are distributed from refineries to service stations, bulk plants, etc.[17] These regulations set emission standards for loading racks and on the loading of liquid product, vapor tightness standards for tank trucks, and pressure standards for pressure-vacuum vents on a vapor collection system.[18] Subpart XX also requires the use of vapor collection equipment and requires monthly inspections for equipment leaks.[19]

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[2] 72 Fed. Reg. 27178, 27179 (May 14, 2007).

[3] 40 C.F.R. § 60.100(a) to (b) (2021).

[4] 40 C.F.R. §§ 60.102 to 60.104 (2021).

[5] 40 C.F.R. §§ 60.105 to 60.108 (2021).

[6] 40 C.F.R. § 60.100(a) to (b) (2021).

[7] 40 C.F.R. § 60.102a(b) (2021).

[8] 40 C.F.R. § 60.103a(a) (2021).

[9] 40 C.F.R. § 60.103a(c)(i) (2021).

[10] 40 C.F.R. § 60.103a(j) (2021).

[11] 40 C.F.R. §§ 60.104a to 60.108a (2021).

[12] 40 C.F.R. §§ 60.590 to 60.590a (2021).

[13] 40 C.F.R. § 60.690 (2021).

[14] 40 C.F.R. §§ 60.692-1 to 60.692-4 (2021).

[15] 40 C.F.R. §§ 60.692-5, 60.695 to 60.698 (2021).

[16] 40 C.F.R. §§ 60.693-1 to 60.694 (2021).

[17] For the regulatory definition, *see* 40 C.F.R. § 60.501 (2021).

[18] 40 C.F.R. § 60.502 (2021).

[19] 40 C.F.R. §§ 60.502(a), .505 (2021).

## § 29:184 Regulation of Air Emissions: National Emissions Standards for Hazardous Air Pollutants

The national emissions standards for hazardous air pollutants (NESHAPs) program of the CAA is another significant source of pollution regulation of petroleum refineries.[1] NESHAPs sets emissions standards for hazardous air pollutants (HAPs) applicable to new, modified, and existing major sources within defined source categories. Subject facilities must install the maximum achievable control technology (MACT) to control emissions of HAPs.

HAPs are air toxics. In addition to those specifically listed by statute,[2] HAPs may include "substances which are known to be, or may reasonably be anticipated to be, carcinogenic, mutagenic, teratogenic, neurotoxic, which cause reproductive disruption, or which are acutely or chronically toxic[] . . . ."[3] The list of HAPs emitted by petroleum refineries is published at 40 CFR Part 63, Appendix to Subpart CC, Table 1. Notably, these HAPs include the BTEX compounds (benzene, toluene, ethylbenzene, and xylene).

MACT refers to

> the maximum degree of reduction in emissions . . . that . . ., taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable . . . through application of measures, processes, methods, systems or techniques . . . .[4]

MACT may include measures that:

1) Reduce or eliminate emissions of HAPs through process changes, substitutions of materials, or other modifications;
2) Enclose systems of processes to eliminate emissions;
3) Collect, capture or treat such pollutants when released from a point source;
4) Are design, equipment, work practice, or operational standards (including requirements for operator training or certification); or
5) Are a combination of these.[5]

A stationary source is a "major source" subject to NESHAPs if it falls within an EPA-designated source category and emits at least 10 tpy of any single HAP or 25 tpy of any combination of HAPs.[6] On October 1, 2020, EPA finalized a new rule that allows sources once categorized as "major" to reclassify as a non-major "area source" after reducing emissions below the major threshold.[7]

EPA has designated multiple source categories subject to NESHAPs that affect petroleum refining and marketing operations. Two of these, commonly referred to as "MACT 1" and "MACT 2," pertain directly to refineries. MACT 1, promulgated at 40 C.F.R. Part 63 Subpart CC, regulates HAPs emissions from miscellaneous process vents, storage vessels, wastewater, equipment leaks, gasoline loading racks, marine tank vessel loading, and heat exchange systems at petroleum refineries.[8] MACT 2, promulgated at Subpart UUU, regulates HAPs emissions from process vents on

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**[Section 29:184]**

[1] CAA § 112(d)(2) to (3), 42 U.S.C. § 7412(d)(2) to (3).

[2] CAA § 112(b)(1), 42 U.S.C. § 7412(b)(1).

[3] CAA § 112(b)(2), 42 U.S.C. § 7412(b)(2).

[4] CAA § 112(d)(2), 42 U.S.C. § 7412(d)(1).

[5] CAA § 112(d)(2), 42 U.S.C. § 7412(d)(1).

[6] CAA § 112(a)(1), 42 U.S.C. § 7412(a)(1).

[7] 40 C.F.R. § 63 subpart A (2021).

[8] 40 C.F.R. § 63.640 (2021).

catalytic cracking units (CCUs, including fluid catalytic cracking units (FCCUs)), catalytic reforming units, and sulfur recovery units (SRUs).[9] The regulations include operational standards for decoking of delayed coking units[10] and "fenceline monitoring" requirements for monitoring for regulated HAPs in the proximity of refineries.[11]

EPA has also promulgated NESHAPs for industrial process cooling towers, which are common components of petroleum refineries. Subpart Q sets standards for emissions of chromium compounds, which are released from towers during the cooling process.[12] NESHAPs also exist for certain site-remediation technologies and practices, which are often used at petroleum refineries to clean up contaminated soil and water. These regulations, at Subpart GGGGG, aim to control emissions of organic HAPs by imposing MACT requirements and work practices designed to limit emissions.[13]

The distribution and marketing segment of the downstream industry is also subject to NESHAPs. Subparts R, BBBBBB, and CCCCCC impose limitations on the emission of air toxics from, respectively, area source categories such as bulk gasoline terminals and pipeline breakout stations;[14] gasoline distribution bulk terminals, bulk plants, and pipeline facilities;[15] and gasoline dispensing facilities.[16] The general aim of these NESHAPs is to control releases of HAPS during the loading, unloading, and transportation of refined products like gasoline, and limit vapor leaks from pumps, valves, and similar equipment. Subpart Y requires large marine loading terminals for refined products to reduce emissions of VOCs using Reasonably Available Control Technology (RACT) and to limit emissions of HAPs using MACT.[17] Special NESHAPs also apply, under Subpart BB, to facilities which transfer benzene (a refined product), such as where it is loaded into trucks, railcars, or marine vessels.[18]

## § 29:185 Regulation of Air Emissions: Refined Fuel Products

One of the distinctive features of environmental regulation of petroleum refineries is that, in addition to their operation, the products that refineries manufacture are themselves subject to significant regulation. Described as the most burdensome and costly regulation of the industry,[1] the CAA Amendments of 1990 established national gasoline standards and empowered states to adopt their own unique fuel programs to meet local air quality needs.[2] To implement one of these so-called "boutique" fuel program, states must receive approval from EPA in their SIPS. Approval is conditioned on a demonstration that the state fuel program is strictly necessary to achieve the NAAQs that the SIP implements.[3] A list of approved state fuel programs

[9] 40 C.F.R. § 63.1562 (2021).

[10] 40 C.F.R. § 63.657 (2021).

[11] 40 C.F.R. § 63.658 (2021).

[12] 40 C.F.R. § 63 subpart Q (2021).

[13] 40 C.F.R. § 63 subpart GGGGG (2021).

[14] 40 C.F.R. § 63 subpart R (2021).

[15] 40 C.F.R. § 63 subpart BBBBBB (2021).

[16] 40 C.F.R. § 63 subpart CCCCCC (2021).

[17] 40 C.F.R. § 63 subpart Y.

[18] 40 C.F.R. § 61 subpart B (2021).

**[Section 29:185]**

[1] Saha & Gamkar, *supra* note 5, at 38.

[2] 71 Fed. Reg. 78192, 78192 to 99 (Dec. 28, 2006).

[3] CAA § 211(c)(4)(C)(i), 42 U.S.C. § 7545(c)(4)(C)(i).

is maintained in the Federal Register and EPA's website.[4]

The purpose of the gasoline standards programs is to reduce ground-level ozone (smog) and toxic emissions from fuel burned in motor vehicles.[5] The programs cover standards for sulfur content,[6] the content of toxic chemicals like benzene,[7] Reid vapor pressure (RVP),[8] winter oxygenates,[9] and reformulated gasoline (RFG).[10] RVP standards require use of specially formulated gasoline that evaporates at a higher temperature than normal gasoline, which reduces emissions of VOCs and hydrocarbons that contribute to smog. The winter oxygenates program mandates addition of oxygenates to gasoline during winter months to increase combustion efficiency and reduce carbon monoxide emissions. The RFG program prohibits the sale of non-reformulated gasoline, or "conventional" gasoline, in certain areas of the country in nonattainment for ozone. The program aims to improve air quality in certain areas of the county through the use of gasoline that is specifically formulated to reduce motor vehicle emissions of ozone-forming compounds.[11]

The gasoline standards programs had a profound effect on the refining industry. Before the 1990 Amendments, there were three types of gasoline sold in the United States: regular, midgrade, and premium. By 2002, under federal and state fuel programs, that number had increased to 21 types of gasoline.[12] The proliferation of gasoline types disrupted the operation of refineries as well as the gasoline distribution system. Individual gasoline types must be fed through product pipelines in batches and cannot be comingled. To produce a new type of gasoline, refineries often must incur large capital investments. These investments are difficult to recoup when the gasoline may be marketed in a limited number of states and localities.[13] Owing to these dislocations, by 2005 the gasoline production and distribution system had become vulnerable to supplies problems and disruption.[14]

In response to these and related issues in the gasoline market, the Energy Policy Act of 2005 amended the CAA to restrict EPA's authority to approve state boutique fuel programs.[15] Under the 2005 Act, EPA cannot approve a state fuel if it would cause the total number such fuels to increase above the number that had been approved as of September 1, 2004. Further, before approving a new fuel, EPA must consult with the Department of Energy to ensure the new fuel will not cause a supply or distribution interruption or have a significant adverse impact on fuel producibility in the affected or continuous areas.[16] With certain exceptions, EPA also has the discretion to deny approval of a state fuel unless the fuel is already in an existing SIP within the same PADD.[17]

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[4] CAA § 211(k)(1); 71 Fed. Reg. 78192, 78192 to 99 (Dec. 28, 2006); U.S. EPA, *State Fuels*, https://www.epa.gov/gasoline-standards/state-fuels.

[5] The gasoline regulations are under 40 C.F.R. pt. 80 (2021).

[6] 40 C.F.R. pt. 80 subparts H & O (2021).

[7] 40 C.F.R. pt. 80 subparts J & L (2021).

[8] 40 C.F.R. § 80.27 (2021).

[9] 40 C.F.R. § 80 subpart C (2021).

[10] 40 C.F.R. § 80 subparts D & E (2021).

[11] CAA § 211(k)(5), 42 U.S.C. § 7545(k)(5); 80 Fed. Reg. 6658, 6659 (Feb. 6, 2015).

[12] Pierce Jr., *supra* note 17, at 169.

[13] Pierce Jr., *supra* note 17, at 169–70.

[14] Koschnitzky, *Refining Regulation: The Oil Refinery Regulatory Framework after the Energy Policy Act of 2005*, 15 MO. ENVTL. L. & POL'Y REV. 89, 104–08 (2007).

[15] 71 Fed. Reg. 78192, 78192 to 99 (Dec. 28, 2006).

[16] CAA § 211(v)(4)(C)(v)(IV), 42 U.S.C. § 7545(v)(4)(C)(v)(IV).

[17] CAA § 211(v)(4)(C)(v)(V), 42 U.S.C. § 7545(v)(4)(C)(v)(V).

## § 29:186 Regulation of Water Discharges: Effluent Limitations for Petroleum Refining Point Sources

Refineries use thousands of gallons of water per day for production and cooling processes, and much of this becomes wastewater. Sources of wastewater include, without limitation, the desalting process, tank bottoms, cooling towers, and condensate blowdown.[1] Most of the wastewater that is not reused is generally treated on site and discharged into surface waters or publicly owned treatment works (POTWs).[2] Since 1974, these discharges have been subject to EPA's petroleum refining effluent guidelines and standards, promulgated under the national pollutant discharge elimination system (NPDES) of the Clean Water Act (CWA).[3] In general, the NPDES program prohibits discharges of pollutants through a point source into the waters of the United States without a NPDES permit.[4]

For direct discharges into surface water, effluent guidelines and standards are incorporated into a required NPDES permit. The standards require that existing point sources in the following source subcategories achieve certain effluent limitations for various pollutants: topping, cracking, petrochemical, lube manufacturing, and integrated operations.[5] The applicable effluent limitations depend on the type of pollutant and are based variously on the best available technology economically achievable (BAT), best practicable control technology currently available (BPT), and best conventional pollutant control technology (BCT).[6] The regulations additionally impose new source performance standards (NSPS) for new point sources in each category, which function similarly to NSPS under the CAA.[7]

Discharges into POTW are subject to the national pretreatment program component of the NPDES program. Under this program, the effluent guidelines and standards require separate pretreatment standards for existing and new sources in each of the covered source subcategories.[8]

## § 29:187 Regulation of Water Discharges: Stormwater Discharges

The NPDES program requires industrial facilities to obtain a permit for wastewater discharges from the facility.[1] Petroleum refineries are subject to this additional requirement of NPDES despite a broad exemption from the program for upstream oil and gas facilities. Section 402(l)(2) of the CWA prohibits EPA and states from requiring a NPDES permit for uncontaminated stormwater runoff

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**[Section 29:186]**

[1] *See supra* §§ 29:103 to 29:112 (discussing the refining process and sources of water discharges).

[2] Saha & Gamkar, *supra* note 5, at 42.

[3] The regulations are under 40 C.F.R. pt. 419 (2021).

[4] FWPCA § 404, 33 U.S.C. § 1342.

[5] 40 C.F.R. § 419 subparts A to E (2021). For EPA's summary of the applicability of each subpart, *see* U.S. EPA, DETAILED STUDY OF THE PETROLEUM REFINING CATEGORY—2019 REPORT, Table 2-1 (2019).

[6] 40 C.F.R. § 419.12 to 419.14 (2021) (topping subcategory), 419.22 to 419.24 (2021) (cracking subcategory), 419.32 to 419.34 (2021) (petrochemical subcategory), 419.42 to 419.44 (2021) (lube subcategory), 419.52 to 419.54 (2021) (integrated subcategory).

[7] 40 C.F.R. § 419.16 (2021) (topping subcategory), 419.26 (2021) (cracking subcategory), 419.36 (2021) (petrochemical subcategory), 419.46 (2021) (lube subcategory), 419.56 (2021) (integrated subcategory).

[8] 40 C.F.R. §§ 419.15 & 419.17 (2021) (topping subcategory), 419.25 & 419.27 (2021) (cracking subcategory), 419.35 & 419.37 (2021) (petrochemical subcategory), 419.45 & 419.47 (2021) (lube subcategory), 419.55 & 419.57 (2021) (integrated subcategory).

**[Section 29:187]**

[1] FWPCA § 402(p), 33 U.S.C. § 1342(p).

discharges from oil and gas exploration, production, processing, treatment operations, and transmission facilities.[2] EPA has interpreted this exemption not to apply to conventional petroleum and petrochemical refineries, oil shale refineries, cracking plants, or refined products pipelines that connect refineries with local and distant product storage facilities.[3]

## § 29:188 Regulation of Water Discharges: Spill Prevention, Control and Countermeasures Plans and Facility Response Plans

Petroleum refineries are subject to the spill prevention, control and countermeasures (SPCC) requirements of the CWA and its oil pollution prevention regulations.[1] Covered facilities are those non-transportation-related facilities that store greater than 1,320 gallons of "oil" in aggregate above-have storage or that have 42,000 gallons of completely buried "oil" storage capacity, and that has a "reasonable expectation of an oil discharge to navigable waters of the United States and adjoining shorelines."[2] "Oil" is defined to include petroleum and nonpetroleum-based oils, crude oil, and—importantly for this sector of the industry—refined products.[3] Oil storage that is permanently closed is exempt from the SPCC requirements.[4] Additionally, because refinery tank farms can contain large volumes of "oil," refineries may also have to prepare facility response plans (FRPs) under the 1990 Oil Pollution Act amendments to the CWA.[5] A facility is subject to the FRP requirement if it could reasonably be expected to cause "substantial harm" to the environment by discharging oil into or on waters of the United States.[6] Refining and downstream facilities that could pose a "significant and substantial harm" must have their FRPs approved by the appropriate EPA regional administrator.[7] EPA considers the following factors in determining whether a facility poses a "significant and substantial harm": age of tanks, type of transfer operations, oil storage capacity, lack of secondary containment, proximity to wildlife and sensitive environments or drinking-water intakes, spill history and frequency of past discharges, or other information, including local impacts on public health.[8]

## § 29:189 Regulation of Water Discharges: Discharge Reporting

The CWA requires any person in charge of a petroleum refinery to report to the federal government any discharge of "harmful quantities" of oil or hazardous

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[2] 40 C.F.R. § 122.26(a)(2)(ii) (2021).

[3] 71 Fed. Reg. 894, 895 (Jan. 6, 2006) (stating the exemption applies only to operations within the NAICS codes for oil and gas extraction, drilling, support activities, and pipeline transportation); *see also* U.S. EPA, *Oil and Gas Stormwater Permitting*, https://www.epa.gov/npdes/oil-and-gas-stormwater-permitting; U.S. EPA, 2006 OIL AND GAS STORMWATER FINAL RULE Q&A 3 (2006).

**[Section 29:188]**

[1] FWPCA § 311(j), 33 U.S.C. § 1321(a)(1); 40 C.F.R. § 112 (2021). For discussion of the SPCC program, *see* § 13:143 of this treatise.

[2] 40 C.F.R. § 112.1 (2021).

[3] FWPCA § 311(a)(1), 33 U.S.C. § 1321(a)(1).

[4] 40 C.F.R. § 112.1(b)(4) (2021).

[5] For discussion of the FRP requirements, *see* §§ 29:103 to 29:112.

[6] FWPCA § 311(j)(5), 33 U.S.C. § 1321(j)(5).

[7] FWPCA § 311(j)(5)(E), 33 U.S.C. § 1321(j)(5)(E).

[8] 40 C.F.R. § 112.20(f)(3) (2021).

substance from the facility "as soon as he has knowledge of" the discharge.[1] EPA has defined "harmful quantities" by the "sheen rule," which requires reporting of discharges that "[c]ause a film or sheen upon or discoloration of the surface of the water . . . ."[2]

## § 29:190 Regulation of Hazardous Substances: Resource Conservation and Recovery Act

The petroleum refining process can also generate large amounts of hazardous and non-hazardous solid wastes regulated under the Resource Conservation and Recovery Act (RCRA).[1] The 1984 Hazardous Solid Waste Amendments (HSWA) to RCRA prohibit the land disposal of untreated hazardous wastes and require EPA to set maximum concentration levels or prescribe treatment standards for hazardous waste before land disposal is permissible.[2] EPA maintains four separate lists of hazardous wastes that are subject to land disposal restrictions. Of primary importance to the refining industry are the K list[3] and F list.[4]

The K list identifies source-specific wastes. EPA initially listed several petroleum refinery wastes in 1980.[5] In 1998, as a result of a consent decree resolving a lawsuit filed by the Environmental Defense Fund, EPA listed several additional refinery wastes on schedule K.[6] This was accomplished pursuant to section 3001(e)(2) of RCRA, which required EPA to determine whether to list as hazardous a number of waste residuals—including several generated by petroleum refining.[7]

F listings target more general types of waste than K listings. These listings were intended to complement the more specific listings for K-listed wastes, K051 and K048, by covering all types of petroleum refinery wastewater treatment sludges and floats, rather than only the specific ones listed in K.[8]

Petroleum Refining "K" Wastes

| | | |
|---|---|---|
| K048 | Dissolved air flotation (DAF) float from the petroleum refining industry | (T) |
| K049 | Slop oil emulsion solids from the petroleum refining Industry | (T) |
| K050 | Heat exchanger bundle cleaning sludge from the petroleum refining industry | (T) |
| K051 | API separator sludge from the petroleum refining Industry | (T) |
| K052 | Tank bottoms (leaded) from the petroleum refining Industry | (T) |
| K169 | Crude oil storage tank sediment from petroleum refining operations | (T) |
| K170 | Clarified slurry oil tank sediment and/or in-line filter/separation solids from petroleum refining operations | (T) |
| K171 | Spent Hydrotreating catalyst from petroleum refining operations, including guard beds used to desulfurize feeds to other catalytic reactors (this listing does not include inert support media) | (I, T) |

**[Section 29:189]**

[1]FWPCA § 311(b)(3)–(5), 33 U.S.C. § 1321(b)(3) to (5).

[2]40 C.F.R. § 110.3 (2021). For discussion of discharge reporting requirements and the sheen rule, *see* §§ 29:103 to 29:112.

**[Section 29:190]**

[1]For discussion of RCRA's requirements and restrictions, *see* Chapter 14 of this treatise.

[2]RCRA § 3004(d)(1), 42 U.S.C. § 6924(d)(1). The Universal Treatment Standards are maintained at 40 C.F.R. § 268.40 (2021).

[3]40 C.F.R. § 261.32 (2021).

[4]40 C.F.R. § 261.31 (2021).

[5]45 Fed. Reg. 33064, 33123 (May 19, 1980).

[6]EDF v. Whitman, No. 89–0598 (D. D.C. 1994).

[7]63 Fed. Reg. 42110 (Aug. 6, 1998) (citing (RCRA § 3001(e)(2), 42 U.S.C. § 6921(e)(2)).

[8]50 Fed. Reg. 5637 (Feb. 11, 1985).

| | | |
|---|---|---|
| K172 | Spent Hydrorefining catalyst from petroleum refining operations, including guard beds used to desulfurize feeds to other catalytic reactors (this listing does not include inert support media). | (I, T) |
| K176 | Baghouse filters from the production of antimony oxide, including filters from the production of intermediates (e.g., antimony, metal or crude antimony oxide). | (E) |
| K177 | Slag from the production of antimony oxide that is speculatively accumulated or disposed, including slag from the production of intermediates (e.g., antimony metal or crude antimony oxide). | (T) |
| K178 | Residues from manufacturing and manufacturing- site storage of ferric chloride from acids formed during the production of titanium dioxide using the chloride-ilmenite process. | (T) |

Petroleum Refining "F" Wastes

| | | |
|---|---|---|
| F037 | Petroleum refinery primary oil/water/solids separation sludge—Any sludge generated from the gravitational separation of oil/water/solids during the storage or treatment of process wastewaters and oily cooling wastewaters from petroleum refineries. Such sludges include, but are not limited to, those generated in oil/water/solids separators; tanks and impoundments; ditches and other conveyances; sumps; and stormwater units receiving dry weather flow. Sludge generated in stormwater units that do not receive dry weather flow, sludges generated from non-contact once-through cooling waters segregated for treatment from other process or oily cooling waters, sludges generated in aggressive biological treatment units as defined in § 261.31(b)(2) (including sludges generated in one or more additional units after wastewaters have been treated in aggressive biological treatment units) and K051 wastes are not included in this listing. This listing does include residuals generated from processing or recycling oil-bearing hazardous secondary materials excluded under § 261.4(a)(12)(i), if those residuals are to be disposed of | (T) |
| F038 | Petroleum refinery secondary (emulsified) oil/water/solids separation sludge—Any sludge and/or float generated from the physical and/or chemical separation of oil/water/solids in process wastewaters and oily cooling wastewaters from petroleum refineries. Such wastes include, but are not limited to, all sludges and floats generated in: induced air flotation (IAF) units, tanks and impoundments, and all sludges generated in DAF units. Sludges generated in stormwater units that do not receive dry weather flow, sludges generated from non-contact once-through cooling waters segregated for treatment from other process or oily cooling waters, sludges and floats generated in aggressive biological treatment units as defined in § 261.31(b)(2) (including sludges and floats generated in one or more additional units after wastewaters have been treated in aggressive biological treatment units) and F037, K048, and K051 wastes are not included in this listing | (T) |

## § 29:191 Regulation of hazardous substances: underground injection wells

Petroleum refineries are among the most significant users of Class I underground injection wells for hazardous and non-hazardous fluid wastes. Class I wells, authorized by the underground injection control (UIC) program of the federal Safe Drinking Water Act (SDWA),[1] are used to inject hazardous and non-hazardous wastes (as defined by RCRA)[2] into deep, confined rock formations thousands of feet below underground sources of drinking water. Most Class I wells are found in the Gulf Coast and Great Lakes areas, where much of the country's refining capacity is located and where the geology is well suited to this type of well. Class I wells are subject to extensive requirements relating to siting, construction, operation, monitoring, testing, recordkeeping, reporting, and closure.[3]

## § 29:192 Regulation of Hazardous Substances: Comprehensive Environmental Response, Compensation, and Liability Act

Refinery facilities that fall short of complying with RCRA could also run afoul of the Comprehensive Environmental Response, Compensation, and Liability Act's (CERCLA's) regime of strict liability for the cleanup of sites where there has been a

**[Section 29:191]**

[1] 42 U.S.C. § 300f.

[2] RCRA § 3004(f), 42 U.S.C. § 6924(f).

[3] 40 C.F.R. §§ 146.1 to 146.10 (2021) (general UIC requirements), 146.11 to 146.16 (standards applicable to Class I wells). For discussion of Class I permitting requirements, *see* § 14:70 of this treatise.

release or threatened release of hazardous substances.[1] Critically, to define "hazardous substances," CERCLA incorporates anything classified as a hazardous or toxic waste, chemical, substance, emission, or effluent under RCRA, as well as the CAA, CWA, and the Toxic Substances Control Act[2]—all of which apply to petroleum refining operations. The wide scope of liability, broad definition of hazardous substances, and the potentially incredible costs of cleanup, combine to make CERCLA one of the most financially consequential environmental regulations of the downstream oil and gas industry. There are a number of exclusions from CERCLA's definition of hazardous wastes relevant to the petroleum refining sector. Oil-bearing hazardous secondary materials, such as sludges, byproducts, or spent materials, that are generated at a petroleum refinery are excluded if they are reused in the petroleum refining process, such as in distillation, catalytic cracking, fractionation, or thermal cracking (coking) processes. This exclusion is lost, however, if the material is placed on the land or "speculatively accumulated before being so recycled." The exclusion does not cover materials inserted into certain thermal cracking units.[3] Oil that is reclaimed from secondary materials (including wastewater) generated from normal refining, bulk storage, and transportation practices and recycled in the same manner is also excluded.[4] Petrochemical recovered from oil from an associated organic chemical manufacturing facility is also excluded if reused in the petroleum refining process.[5] Groundwater that is hazardous only because it exhibits the toxicity characteristic of 40 C.F.R. § 261.24 and that is reinjected through an underground injection well pursuant to free phase hydrocarbon recovery operations at petroleum refineries, petroleum marketing terminals, petroleum bulk plants, petroleum pipelines, and petroleum transportation spill sites is excluded if conducted before January 25, 1993, or subsequently under certain conditions.[6]

Additionally, CERCLA excludes from the definition of "hazardous substances" "petroleum, including crude oil or any fraction thereof" and "natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel . . . ."[7] Courts have interpreted this "petroleum exclusion" to encompass gasoline leaking from underground storage tanks, even where certain additives in the gasoline themselves had been designated as hazardous substances.[8] EPA, however, interprets the exclusion narrowly, such that it encompasses only crude oil and fractions of crude oil, including the hazardous substances, such as benzene, that are indigenous in those petroleum substances. Further, EPA's interpretation encompasses within the exclusion hazardous substances that are normally mixed with or added to crude oil or crude oil fractions during the refining process, including hazardous substances the levels of which are increased during refining. The exclusion does not cover, under EPA's interpretation, hazardous substances that are added to petroleum or that

**[Section 29:192]**

[1] CERCLA § 107(a)(4), 42 U.S.C. § 9607(a)(4). For discussion of CERCLA, *see* Chapter 14 of this treatise.

[2] CERCLA § 101(14), 42 U.S.C. § 9601(14). EPA lists the designated hazardous substances at 40 C.F.R. § 302.4 (2021).

[3] 40 C.F.R. § 261.4(a)(12)(i) (2021).

[4] 40 C.F.R. § 261.4(a)(12)(ii) (2021).

[5] 40 C.F.R. § 261.4(a)(18) (2021).

[6] 40 C.F.R. § 261.4(b)(11) (2021).

[7] CERCLA § 101(14), 42 U.S.C. § 9601(14).

[8] Wilshire Westwood Associates v. Atlantic Richfield Corp., 881 F.2d 801, 805, 30 Env't. Rep. Cas. (BNA) 1065, 19 Envtl. L. Rep. 21313 (9th Cir. 1989).

increase in concentration as a result of contamination of the petroleum during use.[9]

## § 29:193 Regulation of Hazardous Substances: The Toxic Substances Control Act

As manufacturers and users of chemical substances, petroleum refineries are subject to the provisions of Subtitle I of the Toxic Substances Control Act (TSCA). The law regulates the manufacture, sale, and use in commerce of all existing and newly manufactured or imported chemicals in the United States that pose "an unreasonable risk to health or to the environment." TSCA applies to any person, including refineries, that manufactures, processes, distributes in commerce, uses, or disposes of a regulated chemical substance.[1] "Chemical substance" is defined broadly to include "any organic or inorganic substance of a particular molecular identity," but excludes substances controlled under other federal statutes, such as pesticides, tobacco products, nuclear materials, and food, cosmetics, and drugs.[2]

EPA must maintain the TSCA Chemical Substance Inventory, which includes more than 86,000 chemical substances manufactured and used in the United States.[3] Under the chemical data reporting (CDR) rule (formerly the inventory update rule (IUR)), every four years, manufacturers that meet or exceed production volume thresholds (generally 25,000 pounds or more of a chemical substance) must report information to EPA about their production and use of chemicals in commerce.[4] The manufacture of new chemical substances, or the new use of existing substances, is prohibited unless the manufacturer gives EPA at least 90 days' notice (premanufacture notice) and the EPA Administrator, after a review, determines it does not present an unreasonable risk of injury to health or the environment.[5] New chemical substances are subsequently added to the inventory.

Under Section 6(a), EPA may promulgate rules restricting or prohibiting the manufacturing, processing, or distribution commerce of certain chemical substances.[6] Section 21 permits parties to petition EPA to undertake 6(a) rulemakings. On November 4, 2019, EPA denied such a petition from the Public Employees for Environmental Responsibility to promulgate a Section 6(a) rule prohibiting petroleum refineries from using hydrofluoric acid in manufacturing processes and require a phase-out within two years.[7]

## § 29:194 Regulation of Hazardous Substances: Emergency Planning and Community Right-to-Know Act

By virtue of the presence of a number of hazardous substances in significant quantities at petroleum refining facilities, refineries are subject to the Emergency

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[9]Memorandum from EPA General Counsel Francis S. Blake to Assistant Administrator for Solid Waste and Emergency Response J. Winston Porter Regarding Scope of the CERCLA Petroleum Exclusion Under Sections 101(14) and 104(a)(2), at 5 (Jul. 31, 1987); U.S. EPA, *Specific Substances Excluded Under CERCLA Petroleum Exclusion*, https://www.epa.gov/epcra/specific-substances-excluded-under-cercla-petroleum-exclusion.

**[Section 29:193]**

[1]*See* TSCA § 4(a)(1)(A), 15 U.S.C. § 2603(a)(1)(A).

[2]TSCA § 1(2), 15 U.S.C. § 2602(2).

[3]TSCA § 8(b), 15 U.S.C. § 2608(b).

[4]TSCA § 8(a), 15 U.S.C. § 2607(a); 40 C.F.R. pt. 711 (2021).

[5]TSCA § 5(a), 15 U.S.C. § 2604(a); 40 C.F.R. §§ 720 to 23 (2021).

[6]TSCA § 6(a), 15 U.S.C. § 2605(a); 40 C.F.R. §§ 750 to 51 (2021).

[7]84 Fed. Reg. 60986 (Nov. 12, 2019).

Planning and Community Right-to-Know Act (EPCRA).[1] EPCRA creates a framework to require facilities, including petroleum refineries, where extremely hazardous substances (EHSs) are present to disclose these substances to local and state authorities to report their accidental release. EHS are listed in Appendix A to 40 C.F.R. Part 355. Refineries are covered facilities if they employ 10 or more full-time-equivalent employees (as they invariably do) and manufacture or process the listed chemicals in excess of applicable thresholds.[2] Covered facilities must annually submit a material safety data sheet (MSDS), as well as an emergency and hazardous chemical inventory form, to the local and state planning authorities and local fire departments for each hazardous chemical (as defined under the Occupational Safety and Health Act).[3] Additionally, refineries are subject to EPA's Toxics Release Inventory (TRI) program, which requires reporting of the quantities of listed toxic chemicals that the refinery uses, manufactures, or processes above applicable thresholds during the previous year.[4] Refineries must also submit either a Tier I or Tier II hazardous chemical inventory form, which identifies the amount, location, and potential hazards of each EHS on site at any point during the year.[5]

## § 29:195 Regulation of Underground Storage Tanks

The marketing sector of the downstream industry makes great use of underground storage tanks (USTs) to store refined products; in particular, for gasoline at filling stations. Leaking USTs can contaminate underground sources of drinking water. These issues led EPA to promulgate regulations addressing USTs under the authority of amendments to Subtitle I of the Solid Waste Disposal Act of 1984 (amending RCRA),[1] which in turn was amended by the Energy Policy Act of 2005.[2] EPA revised its UST regulations in July 2015 to increase requirements on operation and maintenance and leak prevention and detection.[3] Generally, the UST regulations impose performance standards for new USTs, upgrading standards for existing systems,[4] and general operating requirements for all USTs. These operating requirements cover spill and overfill controls, operation and corrosion protection, reporting and recordkeeping, periodic testing of spill prevention and containment mechanisms, and periodic inspections.[5] Additionally, the regulations mandate release detection, reporting and investigation, and response and corrective action procedures.[6] The regulations also address closure procedures and recordkeeping and financial responsibility requirements.[7]

The statutes permit states to develop their own UST programs with the approval

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**[Section 29:194]**

[1]EPCRA is discussed in §§ 14:148 to 14:172 of this treatise.

[2]EPCRA § 313(b), 42 U.S.C. § 11023(b); 40 C.F.R. § 372.5 (2021).

[3]EPCRA § 311(a), 42 U.S.C. § 11021(a).

[4]EPCRA § 313(a), 42 U.S.C. § 11023(a). The thresholds are set under subsection (f).

[5]EPCRA § 312(a) & (d), 42 U.S.C. § 11022(a) & (d).

**[Section 29:195]**

[1]40 C.F.R. § 280 (2021).

[2]RCRA §§ 9001 to 9010, 42 U.S.C.A. § 6991 to 6991m.

[3]80 Fed. Reg. 41566 (Jul. 15, 2015).

[4]40 C.F.R. § 280.20 (new USTs), 280.21 (existing USTs) (2021).

[5]40 C.F.R. §§ 280.30 to 280.36 (2021).

[6]40 C.F.R. §§ 280.40 to 280.45, 280.50 to 280.53, 280.60 to 280.67 (2021).

[7]40 C.F.R. §§ 280.70 to 280.74, 280.90 to 280.116 (2021).

of EPA to operate in lieu of federal standards.[8] State-imposed standards may be more stringent than federal requirements.[9] EPA maintains a list of approved state programs at 40 C.F.R. Part 282 Subpart B.

In 1986, Congress created the Leaking Underground Storage Tank (LUST) Trust Fund to address petroleum releases from federally regulated USTs.[10] The Energy Policy Act of 2005 expanded the permissible uses of funds from the Trust Fund, such that they may be used to oversee cleanups of petroleum releases, enforce cleanups, pay for cleanups at sites where the owner or operator is unknown, unwilling, or unable to respond or which require emergency action, and conduct inspections and other release prevention activities.[11] States and tribes may use Trust Fund money to support these purposes if they enter an assistance agreement with the federal government.

### § 29:196 Federal Statutes Implicated by Permits Issued under the CAA, CWA, and RCRA

Certain federal environmental statutes that do not directly regulate petroleum refining and marketing are implicated nonetheless when a federal agency issues a permit under the CAA, CWA, or RCRA. These include, notably, the National Environmental Policy ACT (NEPA), National Historic Preservation Act (NHPA), Endangered Species Act (ESA), and Coastal Zone Management Act (CZMA). NEPA is triggered by any "major federal action," which is defined to include "approval of specific projects . . . by permit or other regulatory decision under the CAA, CWA, and RCRA."[1] Similarly, NHPA requires any federal agency with the authority to license a project to account for the effects of the project on historic properties.[2] Section 7 of ESA requires federal agencies to consult with the U.S. Fish and Wildlife Service or National Marine Fisheries Services to ensure that "any action authorized . . . by such agency . . . is not likely to jeopardize the continued existence of any endangered species or threatened species or result in destruction or adverse modification of habitat for such purposes."[3] CZMA mandates that private activities requiring a federal permit affecting a coastal use or resource be "fully consistent" with enforceable of the relevant state coastal zone management plan.[4]

Consequently, any time a petroleum refinery or other downstream operation requires a permit from a federal agency, such as a Section 404 dredge and fill permit under the Clean Water Act or a New Source Review permit under the Clean Air Act, the permittee must demonstrate compliance not only with the requirements of the statute under which it seeks a permit, but also the requirements of NEPA, NHPA, ESA, an CZMA. For example, if an existing refinery were to undertake a major modification to increase capacity, it would need to consider whether the modification triggers any Clean Air Act permitting programs, such as NSR, NSPS, and NESHAPS. If so, EPA would be obligated to conduct analyses under NEPA, NHPA, the ESA, and the CZMA before issuing the requested permit. These ad-

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[8] RCRA § 9004(a), 42 U.S.C. § 6991c(a). State UST programs may be approved under 40 C.F.R. § 281 (2021).

[9] RCRA § 9008, 42 U.S.C. § 6991g.

[10] RCRA § 9010(2), 42 U.S.C. § 6991m(2).

[11] RCRA § 9010(2), 42 U.S.C. § 6991m(2).

**[Section 29:196]**

[1] 42 U.S.C. § 4332(2)(C); 40 C.F.R. § 1508.18(b)(4) (2021).

[2] 16 U.S.C. § 470f.

[3] 16 U.S.C. § 1536(a)(2).

[4] 15 C.F.R. §§ 930.50 to 930.53 (2021).

ditional requirements can substantially increase the time and expense of obtaining a permit.

## X. REGULATION OF TRANSPORTATION

### § 29:197 Overview and Background

Almost all natural gas and most liquid petroleum transported in the United States moves by pipeline. This section therefore focuses on environmental regulation of pipeline transportation. The section also briefly describes the regulation of rail transportation of oil, an alternative mode of shipment that increased sharply during the domestic energy revolution because of constraints in pipeline capacity.[1]

Several different legal frameworks regulate the environmental, health, and safety risks of the pipeline networks carrying oil and gas. Federal and state public utility laws, state energy facility siting laws, and federal executive orders govern whether and where pipeline facilities should be built. The cooperative federalist framework of the Pipeline Safety Act governs leaks or spills of products from pipeline facilities.[2] Finally, certain pipeline activities are regulated under media-specific environmental laws such as the Clean Water Act and Clean Air Act.[3]

Environmental regulation of pipeline facilities depends on the type of system, the substance transported, and whether the facilities are part of a system that crosses state or national borders. There are three types of pipeline systems: (1) gathering pipeline systems, which collect raw natural gas or crude oil extracted from production wells and transport it to processing facilities or to transmission networks; (2) transmission pipeline systems, which transport gas, oil, or other petroleum products over long distances; and (3) gas distribution pipeline systems, which deliver gas to local customers. Of these systems, the risks of transmission pipeline systems are subject to the most oversight. The federal government directly considers the environmental effects of interstate gas transmission pipeline projects and pipeline projects involving cross-border facilities in determining whether to approve the projects. In contrast, the effects of other types of systems are primarily regulated through safety standards that are designed to prevent accidents. Unlike the disparate legal frameworks governing pipelines, the risks of rail transportation of oil are governed by one framework comprised of two related laws: federal hazardous materials safety regulations promulgated in 2015 and a federal statute enacted six months later.

### § 29:198 Approval and siting of interstate natural gas transmission pipelines

Under Section 7 of the Natural Gas Act, a natural gas company that intends to construct or extend facilities used for transportation of natural gas in interstate commerce is required to obtain a certificate of public convenience and necessity from

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**[Section 29:197]**

[1]Oil is also transported by barge, vessel, and tanker truck. Environmental regulation of oil-carrying vessels is governed by the Oil Pollution Act, a statute covered in other sections. The U.S. Department of Transportation (DOT) regulates the shipment of oil on roadways under the Hazardous Materials Transportation Act. The DOT's regulations focus on containment of hazardous materials and hazard communication.

[2]49 U.S.C. §§ 60101 to 60143.

[3]For example, as explained in another section of this chapter, construction of a pipeline that results in a discharge of dredged or fill material must obtain a permit from the U.S. Army Corps of Engineers under Section 404 of the Clean Water Act.

the Federal Energy Regulatory Commission (FERC).[1] These facilities include transmission pipelines and the equipment needed to operate a pipeline system, such as compressor stations.

To issue a certificate, FERC must find "that the applicant is able and willing properly to do the acts and to perform the service proposed" and the project "is or will be required by the present or future public convenience and necessity."[2] When considering an application, FERC follows the decision-making procedure in its Certificate Policy Statement.[3] An applicant who proposes to expand an existing pipeline system must first establish that the project is not dependent on subsidies from existing customers.[4] If this threshold test is met or the pipeline is new, FERC considers whether the applicant has addressed adverse effects of the project on other pipelines and their existing customers, on owners of land where the facilities will be sited, and on communities affected by the facilities. FERC then weighs the residual adverse effects against the public benefits of the project, namely, the need for the project. This balancing test is primarily focused on economic effects but includes some environmental issues, such as land disturbance.

FERC's decision to certificate is considered a "major federal action" under the National Environmental Policy Act (NEPA), which means FERC must prepare an Environmental Impact Statement (EIS) for a project if there are significant environmental effects.[5] FERC normally prepares an EIS when there is a major construction project involving a new right-of-way.[6] When the project meets the initial balancing test, FERC proceeds to evaluate the environmental impacts and alternatives. The scope of the environmental analysis has been controversial, particularly the extent to which FERC is required to assess the indirect impacts of the project on climate change.[7] FERC generally defers to the U.S. Department of Transportation's pipeline safety requirements in evaluating the potential for natural gas releases.

If FERC finds that the environmental impacts of the project are acceptable given the public benefits, it issues a certificate and approves the pipeline route and location of other facilities. FERC may impose environmental conditions on the certificate to mitigate adverse impacts.[8] The certificate provides a natural gas company with the authority to use eminent domain to obtain easements for the pipeline project.[9] The certificate is generally the final siting approval, as the Natural Gas Act

**[Section 29:198]**

[1] 15 U.S.C. §§ 717(b), 717f(c). Such interstate facilities include pipelines that extend across state borders and pipelines within a state that are part of a system that transports gas among states.

[2] 15 U.S.C. § 717f(e).

[3] Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC ¶ 61227 (1999), *clarified*, 90 FERC ¶ 61128, *further clarified*, 92 FERC ¶ 61094 (2000) (Certificate Policy Statement). FERC also issues blanket certificates for routine activities that do not require case-specific review. 18 C.F.R. §§ 157.201 to 157.218 (2021).

[4] FERC uses this criterion as a threshold test because it ensures that there is a market need for the pipeline and protects existing customers as well as landowners from the adverse effects of an unnecessary pipeline. 88 FERC ¶ 61227 at 21-22.

[5] *See* 42 U.S.C. § 4332(2)(C).

[6] 18 C.F.R. § 380.6(a)(3) (2021).

[7] In 2017, the D.C. Circuit Court of Appeals held that FERC must quantify the effects of a pipeline project on climate change in an EIS or explain why the agency is unable to do so. Sierra Club v. Federal Energy Regulatory Commission, 867 F.3d 1357, 1375, 85 Env't. Rep. Cas. (BNA) 1035 (D.C. Cir. 2017).

[8] 15 U.S.C. § 717f(e).

[9] 15 U.S.C. § 717f(h).

preempts state and local zoning law.[10]

## § 29:199 Approval and Siting of Other Transmission Pipelines

Interstate natural gas transmission pipeline projects are the only pipeline projects that must be approved by FERC. While FERC regulates the rates and service of interstate oil transmission pipelines under the Interstate Commerce Act,[1] it does not have authority to approve oil pipeline projects or to consider the environmental impacts of these projects.

Thus, state law governs the siting of interstate and intrastate oil transmission pipeline projects and gas transmission pipeline projects. Half of the states require review and approval of at least some types of transmission pipeline projects.[2] In the remaining states, public utility commissions may generally oversee transmission pipeline projects by companies that deliver gas to customers, but there is no specific review of impacts mandated by law.

Some states that require review of transmission pipeline projects employ a process similar to the one used by FERC: a company must seek a certificate of public convenience and necessity or other approval from the state public utility commission. For example, a company that intends to construct a pipeline that will operate as a common carrier in Illinois is required to obtain a certificate in good standing from the state Commerce Commission.[3] In determining whether the public convenience and necessity require issuance of a certificate for an oil pipeline, the commission must consider environmental impacts and impacts to natural resources.[4] Other states review transmission pipeline projects as part of a centralized process for siting energy facilities. These states generally require the decision-maker to determine the acceptability of impacts to the environment. For example, in Connecticut, a company that intends to construct an energy facility—which includes an intrastate gas transmission pipeline—and utilize eminent domain authority must apply to a siting council for a certificate of environmental compatibility and public need.[5] To issue the certificate, the council must conclude that the significant adverse environmental effects of the project "are not sufficient reason to deny the application."[6]

## § 29:200 Trans-Border Oil and Gas Pipeline Projects

Oil and gas transmission pipeline projects that cross the U.S.-Canada or U.S.-Mexico border must obtain a Presidential Permit for the facilities at the border. Courts have upheld this permit requirement as an exercise of the president's constitutional power over foreign affairs. In practice, this means that there is federal review of the environmental impacts of transborder pipeline projects that would not otherwise be subject to federal approval and NEPA, such as intrastate gas transmission pipelines and interstate and intrastate oil transmission pipelines.

By executive order, FERC is vested with the authority to issue a Presidential

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[10] *See, e.g.,* Dominion Transmission, Inc. v. Summers, 723 F.3d 238, 245, 77 Env't. Rep. Cas. (BNA) 1040, 181 O.G.R. 979 (D.C. Cir. 2013), judgment entered, 529 Fed. Appx. 3 (D.C. Cir. 2013).

**[Section 29:199]**

[1] *See* Interstate Commerce Act, 49 U.S.C. app. § 6 (1988).

[2] For a list of the states and the governing laws, *see* Gosman, *Planning for Failure: Pipelines, Risk, and the Energy Revolution*, 81 OHIO ST. L.J. 349 (2020).

[3] 220 Ill. Comp. Stat. 5/15-401(a).

[4] 220 Ill. Comp. Stat. 5/15-401(b)(1), (3).

[5] Conn. Gen. Stat. § 16-50k.

[6] Conn. Gen. Stat. § 16-50p(3)(B), (C).

Permit for construction of natural gas facilities at the border if it is "consistent with the public interest."[1] FERC has not defined this term by rule or in a policy statement. Before FERC may grant the permit, the Secretaries of State and Defense must also recommend approval. If the agencies do not agree, the application is submitted to the president for a final decision.

In addition to a permit, the facilities are required to obtain a separate approval from FERC under Section 3 of the Natural Gas Act.[2] Pursuant to this section, FERC must approve the construction and siting of facilities for import or export of natural gas unless it is not consistent with the public interest. The statute provides that importing gas from or exporting gas to a nation with which the United States has a free trade agreement that grants national treatment to trade in natural gas is "deemed to be consistent with the public interest."[3] FERC is required to grant such Section 3 applications "without modification or delay."[4] Since the U.S.-Mexico-Canada Agreement grants national treatment to natural gas, gas transmission pipelines that cross the borders of Canada and Mexico must be approved under the statute. No similar expedited approval is mandated for the Presidential Permit, however.FERC's practice is to consider applications for a Presidential Permit and Section 3 approval in one proceeding and to balance environmental impacts with the importance of free trade and economic effects. An Environmental Assessment is normally prepared under NEPA to determine if there are significant environmental impacts.[5] To comply with NEPA, FERC's environmental review encompasses indirect environmental impacts caused by the whole pipeline even if it only transports gas within a state and is therefore not otherwise subject to FERC jurisdiction. If the pipeline transports gas in interstate commerce and requires approval under Section 7, FERC generally incorporates all of the authorizations into one proceeding and prepares an EIS. FERC may—and usually does—impose environmental conditions on its approvals.[6]

By separate executive order, the U.S. State Department is authorized to issue a Presidential Permit for construction of oil and petroleum product facilities at the border if it "would serve the national interest."[7] A detailed administrative procedure governs the process for making the decision. The State Department must request the views of certain heads of other departments and agencies, including the Administrator of the Environmental Protection Agency and the Secretaries of Interior and Energy. For applications involving the border with Mexico, the U.S. Commissioner of the International Boundary and Water Commission must also be consulted. An official who disagrees with the State Department's proposed determi-

**[Section 29:200]**

[1] Exec. Order No. 10485, 18 Fed. Reg. 5397 (Sept. 3, 1953). The executive order gave the permitting authority to the Federal Power Commission, the predecessor to FERC, but it is now vested in FERC.

[2] 15 U.S.C. § 717b(a). The authority to approve imports or exports of natural gas under the Natural Gas Act is divided between FERC and the Department of Energy. FERC has the responsibility to "[a]pprove or disapprove the construction and operation of particular facilities, the site at which such facilities shall be located, and with respect to natural gas that involves the construction of new domestic facilities, the place of entry for imports or exit for exports." DOE Delegation Order No. 00-004.00A (effective May 16, 2006). The Department of Energy's Office of Fossil Energy authorizes the import or export of the natural gas.

[3] 15 U.S.C. § 717b(b), (c).

[4] 15 U.S.C. § 717(c).

[5] 18 C.F.R. § 380.5(b)(1) (2021).

[6] 15 U.S.C. § 717b(a); Exec. Order No. 10485, *supra* note 20.

[7] Exec. Order No. 11423, 33 Fed. Reg. 11741 (Aug. 16, 1968), *as amended by* Exec. Order No. 13337, 69 Fed. Reg. 25299 (Apr. 30, 2004).

nation must object within 15 days of being notified. The application is referred to the president for a final decision when the officials cannot agree.

The State Department has not defined the standard for a permit in its regulations; however, in making individual national interest determinations, the department has considered environmental impacts together with other factors such as energy security, economic impacts, and foreign policy objectives. The department's NEPA regulations do not specify how a Presidential Permit for a cross-border facility should be treated under NEPA.[8] In the past, the department has prepared an EA for smaller, intrastate pipeline projects and an EIS for larger, interstate pipeline projects. As with cross-border natural gas facilities, environmental review of the project includes indirect environmental impacts caused by the entire pipeline. In its most recent determinations, the department has also considered other indirect environmental impacts, such as the effects on climate change of the method of production of the oil transported through the pipeline and of the ultimate use of the oil. In issuing permits, the department has relied on the authority to set terms and conditions granted by executive order to impose environmental requirements on the project.

## § 29:201 Oil and Gas Pipeline Safety

The federal Pipeline Safety Act grants the Pipeline and Hazardous Materials Safety Administration (PHMSA) in the U.S. Department of Transportation the authority to establish minimum safety standards for pipeline facilities that are "practicable" and "designed to meet the need for . . . pipeline safety . . . and protecting the environment."[1] PHMSA's broad regulatory authority over pipeline systems does not, however, extend to siting; the statute prohibits the agency from specifying the location or route of a pipeline.[2]

If certified by PHMSA, a state may create its own program to regulate intrastate pipelines and may adopt more stringent standards if they are compatible with the federal minimum standards.[3] PHMSA has exclusive jurisdiction over interstate pipelines.

There are separate safety standards for pipelines that transport natural gas and pipelines that transport hazardous liquids such as oil and petroleum products.[4] While the details of the two programs differ, the general approach to regulation is the same. The safety standards regulate the life cycle of a pipeline system once it has been sited: from the design, installation, and construction; to day-to-day operation; to maintenance and repair of the system; to planning for an emergency; and, finally, to abandonment of the pipeline when it is no longer needed.

When a transmission pipeline system or a gas distribution pipeline system is being newly constructed or part of the system is being replaced, prescriptive requirements and performance standards regulate the design specifications, installation and construction methods, and initial inspections and tests. After the infrastructure is in place, PHMSA cannot require a company to comply with updates to these

[8] Prior to 2020, the State Department identified issuance of a Presidential Permit as an action that would normally require an EA. 22 C.F.R. § 161.7(c)(1) (2021).

**[Section 29:201]**

[1] 49 U.S.C. § 60102.

[2] 49 U.S.C. § 60104(e).

[3] 49 U.S.C. §§ 60104(c), 60105.

[4] 49 C.F.R. § 192 (natural gas), pt. 195 (hazardous liquids) (2021).

safety standards.[5] The risks associated with an existing pipeline system are managed through operation, maintenance, and emergency procedures. Each pipeline company must create a written plan for inspection and maintenance of its system to ensure that it is safely operated and does not exceed the maximum allowable operating pressure.[6]

Transmission pipeline companies must develop special integrity management programs to prevent accidents in protected areas, known as "high-consequence areas."[7] For gas transmission pipelines, a "high-consequence area" is a densely populated area. For hazardous liquid pipelines such as oil and petroleum product pipelines, the term is defined more broadly to include populated areas, commercially navigable waterways, and "unusually sensitive areas."[8] As part of the management program, a company must inspect its pipelines regularly, assess the risks of the system, and remediate conditions that reduce a pipeline's integrity within a set schedule.[9]

To prepare for an accident and mitigate its impacts, each pipeline company must develop "an emergency response plan describing the operator's procedures for responding to and containing releases."[10] These include procedures for establishing liaisons and communicating with state and local officials. Under the Oil Pollution Act, companies that own oil pipelines must also create a facility response plan containing procedures and a list of resources to respond to a worst-case discharge of oil into navigable waters or adjoining shorelines.[11] These plans must be kept on file by PHMSA and redacted versions provided to the public on request.[12]

Only some gathering pipeline systems are subject to safety regulation.[13] Safety standards apply to crude oil gathering pipeline systems in urban areas and certain systems in rural areas that are located in or within one-quarter mile of an unusually sensitive area. Most safety standards also apply to natural gas gathering pipeline systems in more densely populated areas.

## § 29:202 Rail Transportation of Crude Oil

The safety of rail transportation is generally governed by two statutes: the Hazardous Materials Transportation Act (HTMA)[1] and the Federal Railroad Safety Act (FRSA).[2] Under the HMTA, PHMSA is authorized to "prescribe regulations for the safe transportation, including security, of hazardous material in intrastate, inter-

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[5] 49 U.S.C. § 60104(b).

[6] 49 U.S.C. § 60108(a).

[7] 49 U.S.C. § 60109. A gas distribution pipeline company must also create an integrity management plan for its entire system that analyzes the risks to its system and effectively manages leaks. 49 U.S.C. § 60109.

[8] PHMSA has defined an "unusually sensitive area" in its regulations to include sources of drinking water and certain habitats of imperiled, threatened, or endangered species. 49 C.F.R. § 195.6 (2021).

[9] Companies that own gas transmission pipelines in less densely settled areas, known as "moderate-consequence areas," must conduct inspections of these pipelines at least once every 10 years. 49 C.F.R. § 192.710 (2021).

[10] 49 U.S.C. § 60102(d)(5).

[11] 33 U.S.C. § 1321(j)(5). Facility response plans are discussed in more detail in the section on the Oil Pollution Act.

[12] 49 U.S.C. § 60138.

[13] 49 U.S.C. § 60101(b).

**[Section 29:202]**

[1] 49 U.S.C. § 5101.

[2] Federal Railroad Safety Act of 1970, Pub. L. No. 91-458, 84 Stat. 971 (codified as amended at 49

state, and foreign commerce";[3] under the FRSA, the Federal Railroad Administration is authorized to "prescribe, as necessary, appropriate rules, regulations, orders, and standards for all areas of railroad safety."[4]

In 2015, PHMSA and the Federal Railroad Administration promulgated hazardous materials regulations for trains carrying flammable liquids, such as crude oil.[5] Pursuant to these regulations, "high-hazard flammable trains" must meet operational requirements such as routing limitations and speed restrictions. A "high-hazard flammable train" is defined as "a single train transporting 20 or more loaded tank cars of a Class 3 flammable liquid in a continuous block or a single train carrying 35 or more loaded tank cars of a Class 3 flammable liquid throughout the train consist."[6] Six months later, Congress supplemented these standards by requiring all tank cars carrying Class 3 flammable liquids to use safer tank car designs, with a timeline for phasing out trains with an older design.[7] Railroads must also provide "real-time" information on trains carrying hazardous materials to first responders and emergency response officials.[8]

## XI. ENERGY POLICY

### A. ENERGY POLICY ACT OF 2005

### § 29:203 Background and Purpose

The Energy Policy Act of 2005 (EPAct 2005)[1] was an omnibus law that impacted many forms of energy production, technologies, and incentives in the United States, including: (1) energy efficiency; (2) renewable energy; (3) oil and gas; (4) coal; (5) Tribal energy; (6) nuclear energy and related security; (7) vehicles and motor fuels, including ethanol; (8) hydrogen; (9) electricity; (10) energy tax provisions and incentives; (11) hydropower and geothermal energy; and (12) technology to address climate change. The purpose of the EPAct 2005 was to "promote[] dependable, affordable, and environmentally sound production and distribution of energy for America's future."[2] The scope of the EPAct 2005 was broad but this section will focus on the oil and gas provisions found in Title III.[3]

The oil and gas provisions of the EPAct 2005, as stated in the Congressional Testimony, served to "encourage[] more domestic production of oil with incentives such as a streamlined permit process, promote a greater refining capacity to bring more oil to market, and increase the gasoline supply by stopping the proliferation of expensive regional boutique fuels."[4] Congress focused on domestic oil and gas production because gas prices were on the rise—partly as a result of "a worldwide

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U.S.C. § 20101).

[3] 49 U.S.C. § 5103(b).

[4] Federal Railroad Safety Act of 1970, § 202(a).

[5] Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains, 80 Fed. Reg. 26644 (May 8, 2015) (to be codified at 49 C.F.R. §§ 171 to 74, 179).

[6] 49 C.F.R.§ 171.8 (2021).

[7] Fixing America's Surface Transportation Act, Pub. L. No. 114-94, § 7304, 129 Stat. 1312 (Dec. 4, 2015).

[8] Pub. L. No. 114-94, § 7302, 129 Stat. 1312 (Dec. 4, 2015)

**[Section 29:203]**

[1] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594.

[2] STATEMENT BY THE PRESIDENT ON ENERGY POLICY ACT OF 2005, 2005 WL 1864962, at *1.

[3] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 [hereinafter EPAct 2005].

[4] 151 Cong. Rec. H2108-01, H2108, 2005 WL 900321.

explosion in demand"[5]—and the U.S. Department of Energy (DOE) predicted that U.S. oil and natural gas demand would increase 46% by 2025.[6]

One of the overarching goals of the EPAct 2005 was to make the Strategic Petroleum Reserve (SPR) and the Northeast Home Heating Oil Reserve (NEHHOR) permanent. The Energy Policy and Conservation Act of 1975 (EPCA) was passed in response to the 1973–74 Arab oil embargo and established the SPR, an emergency supply of crude oil, to prevent another such situation from disrupting energy supply and markets in the United States.[7] The SPR, currently the world's largest emergency supply of crude oil, is held in four major storage facilities within underground salt caverns in the Gulf Coast region of the United States (Louisiana and Texas) that have a combined authorized storage capacity of 714 million barrels.[8] In 2000, President Clinton issued a directive that required the Energy Secretary to create a two million barrel home heating oil component of the SPR in the Northeast; as a result, the NEHHOR was created.[9] The NEHHOR was intended to provide "a buffer large enough to allow commercial companies to compensate for interruptions in supply during severe winter weather,"[10] but not so large that companies are disincentivized to keep sufficient heating oil stock to respond to routine weather events or recognize that a price increase is an indicator of a rise in demand.[11]

There was a period of several months in 2000 when the authority for the SPR had expired, motivating Congress to make the SPR permanent and establish the NEHHOR by statute. The EPAct 2005 also expanded the SPR authorized volume to one billion barrels and permitted that volume to increase when the oil supply is tight and/or prices are elevated. Additionally, the EPAct 2005 established provisions to acquire oil for the SPR in a way that would minimize impacts to oil prices and markets.[12]

### § 29:204 Natural Gas Act Revisions

Title III Subtitle B of the EPAct 2005 amended the Natural Gas Act of 1938 (NGA)[1] in part to address the introduction and rapid expansion of hydraulic fracturing (fracking), the process wherein high-pressure fluids are injected into coal beds to enhance recovery of oil and natural gas from underground formations. With the rapid expansion of fracking came an increase in the country's proven natural gas reserves and the potential to export gas to other countries in significant volumes, mainly as liquified natural gas (LNG). For the first time, the U.S. had the opportunity to become a net LNG exporter whereas, in years prior, the U.S. faced rising costs of natural gas imports. However, LNG production faced disparate local and state regulation as well as a lack of necessary infrastructure. The EPAct 2005

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[5] 151 Cong. Rec. H2108-01, H2108, 2005 WL 900321.

[6] 151 Cong. Rec. H2108-01, H2108, 2005 WL 900321.

[7] Energy Policy and Conservation Act of 1975, Pub. L. No. 94-163, 89 Stat. 871.

[8] U.S. DOE, *Strategic Petroleum Reserve,* https://www.energy.gov/fe/services/petroleum-reserves/strategic-petroleum-reserve.

[9] *President Clinton Directs Department of Energy to Establish a Home Heating Oil Reserve in the Northeast to Protect Against Shortages,* NAT'L ECON. COUNCIL, July 10, 2000, https://clintonwhitehouse4.archives.gov/WH/EOP/nec/html/MinskNortheastOil000710.html (last visited June 28, 2021).

[10] U.S. DOE, *Northeast Home Heating Oil Reserve: History*, https://www.energy.gov/fe/northeast-home-heating-oil-reserve.

[11] For a detailed discussion of the NEHHOR, *see* report by Anthony Andrews, CONG. RSCH. SERV., R43235, *The Northeast Home Heating Oil Reserve and the National Oilheat Research Alliance.*

[12] EPAct 2005 § 301.

**[Section 29:204]**

[1] Natural Gas Act, 15 U.S.C. §§ 717 to 717w (2000).

aimed to remedy these weaknesses in domestic natural gas production, transportation, and exportation through a centralized and streamlined process to approve natural gas projects. A more detailed discussion of the EPAct 2005's specific fracking provisions is set forth below in Section § 29:210.

## § 29:205 FERC's Role

Through the streamlined process, FERC was given broad regulatory tasks and responsibilities, including "exclusive authority" "to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal"[1] for the export and import of natural gas, to coordinate with the Secretary of Defense in authorizing an LNG facility that will impact a military installation,[2] and to serve as the lead agency in the federal authorization process for interstate natural gas facilities, including LNG terminals.[3] This "lead agency" responsibility entails FERC working with other state and federal agencies to expeditiously complete proceedings and schedules in the natural gas permitting process. Section 313 of the EPAct 2005 defines a "federal authorization" as "any authorization required under Federal law with respect to an application for authorization. . .or a certificate of public convenience and necessity," including "any permits, special use authorizations, certifications, opinions, or other approvals as may be required under Federal law. . . ."[4] FERC's expanded authority over LNG facilities was a result of industry concerns that the existing process was taking too long, too chaotic, and too uncertain in a market where demand was ever increasing. While FERC's authority was expanded to push other federal agencies to stick to a FERC-set schedule in issuing permits for new interstate gas pipeline and LNG terminal development, the EPAct 2005 also included limitations on FERC's authority; these limitations were intended to streamline and minimize rate regulation over LNG terminal services. FERC was not permitted to deny approval of a natural gas project before January 1, 2015, solely because the applicant would use the gas, either in whole or in part, themselves.[5] Further, FERC could not condition approval on: (i) a requirement to offer service to others; (ii) a directive to file rates or tariffs with FERC; or (iii) any other regulation of rates and service.[6] These changes to the NGA codified FERC's policies announced in *Hackberry LNG Terminal LLC*.[7] These rate-related provisions will cease to have effect on January 1, 2030.[8]

## § 29:206 Penalties and Market Manipulation

The EPAct 2005 significantly increased penalties for violations of the NGA, the National Gas Policy Act of 1978 (NGPA),[1] and FERC regulations and orders thereunder. With respect to criminal penalties, the maximum prison term increased from two to five years, and the maximum fine increased from $500 per violation to $50,000 for each day the violation took place. Additionally, violations of emergency

**[Section 29:205]**

[1] 15 U.S.C.A. § 717b(e)(1) (West 2005).

[2] FERC's LNG responsibilities are detailed in EPAct 2005 § 311.

[3] FERC's role as the lead agency is detailed in EPAct 2005 § 313.

[4] EPAct 2005 § 313.

[5] EPAct 2005 § 311(c).

[6] EPAct 2005 § 311(c).

[7] 101 FERC ¶ 61294 (2002), *order on reh'g*, 104 FERC ¶ 61269 (2003).

[8] EPAct 2005 § 311(c).

**[Section 29:206]**

[1] 15 U.S.C. § 3414(c).

orders are subject to fines of up to $1 million per day.[2]

The EPAct 2005 also increased civil penalties under the NGA, the NGPA,[3] and the Federal Power Act[4] to a maximum of $1 million per day (inflation adjusted).[5] This was in response to increased concerns about energy market manipulation after the fallout from the Enron Corporation accounting scandal. Some examples of behavior that have been subject to civil penalties under these statutes include pipeline tariff violations and violations of FERC's capacity release program rules.

Section 315 of the EPAct 2005, which amends the NGA to prohibit market manipulation, is largely patterned off of section 10(b) of the Securities Exchange Act of 1934.[6] This section made it unlawful to use or employ, in connection with the purchase or sale of natural gas or transportation services subject to the jurisdiction of FERC, "any manipulative or deceptive device or contrivance" in contravention of FERC's prescribed rules and regulations.[7] Some examples of behavior that violates this provision of EPAct 2005 are creating artificial conditions that would cause energy market prices to be raised to premiums, uneconomic trading in physical gas markets to benefit related financial positions, and "gaming" energy systems to capture revenues without providing any corresponding benefit to the market.[8]

## § 29:207 Other Natural Gas Provisions

In addition to expanding FERC's responsibilities and role in developing natural gas projects, the EPAct 2005 implemented natural gas market transparency rules,[1] reporting requirements,[2] and the process and jurisdiction of judicial review, designated as the U.S. Court of Appeals for the circuit in which the project would be constructed.[3]

## § 29:208 Gasoline Content Changes and Renewable Fuels

The EPAct 2005 took the first steps towards formulating law that requires renewable fuels to be part of the everyday domestic energy supply. The Clean Air Act (CAA)[1] previously had required that reformulated gasoline contain at least 2% oxygen, which effectively forced refiners and importers to use methyl tertiary butyl ether (MTBE), ethanol, or other oxygenates in their reformulated gasoline to meet this requirement. The goal of the 2% oxygen requirement was to combat poor air quality and reduce emissions of ozone and carbon monoxide. However, MTBE became controversial when it was shown to lead to contamination of water across the country, with petroleum released from leaking underground storage tanks being the leading cause of MTBE contamination of drinking and groundwater.

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[2] EPAct 2005 § 314.

[3] 15 U.S.C. § 3414(c).

[4] 16 U.S.C. § 803(e)(1).

[5] EPAct 2005 § 314.

[6] EPAct 2005 § 315; Securities Exchange Act of 1934, 15 U.S.C. § 78j(b).

[7] EPAct 2005 § 315.

[8] *Staff White Paper on Anti-Market Manipulation Enforcement Efforts Ten Years After EPAct 2005*, Fed. Energy Regulatory Comm'n (Nov. 2016).

**[Section 29:207]**

[1] EPAct 2005 §§ 315–16.

[2] EPAct 2005 § 316.

[3] EPAct 2005 § 313.

**[Section 29:208]**

[1] 42 U.S.C. § 7545.

The EPAct 2005 amended § 211(k) of the CAA to eliminate the 2% oxygen requirement and require that each refinery or importer of gasoline maintain the average annual reductions in emissions of toxic air pollutants that were achieved in their production or distribution from calendar years 2001 and 2002.[2] Refiners and importers, therefore, had to determine how to keep their toxic air emissions low. The purpose of this provision was to prevent backsliding in reductions of emissions of toxic air pollutants and alleviate some of the initial burden on gasoline refiners and importers by establishing a credit trading program for such emissions.

Additionally, in lieu of the 2% oxygen requirement, the EPAct 2005 established the initial renewable fuels standard program, known as the "RFS1" program, under § 211 of the CAA. As discussed further below in Section X, the program required that gasoline produced or imported to the United States contain a certain of volume of renewable fuel—a category that includes not only conventional ethanol, but also natural gas (methane) from landfills and sewage treatment plants, as well as biodiesel.[3] The EPAct 2005 also incentivized the use and development of cellulosic ethanol to "accelerate deployment and commercialization of biofuels" by establishing a formulation that 1 gallon of cellulosic ethanol counts as 2.5 gallons of renewable fuel.[4]

## § 29:209 Hydraulic Fracturing

The EPAct 2005, in seeking to address the rapid expansion of fracking discussed above in Section § 29:205, removed oil and gas fracking from EPA's jurisdiction. Prior to 1997, EPA had not regulated fracking for oil and gas development, because it was not considered an activity subject to regulation under the Safe Drinking Water Act's (SDWA)[1] underground injection control (UIC) program.[2] However, in *Legal Environmental Assistance Foundation, Inc. v. United States Environmental Protection Agency*,[3] the Eleventh Circuit Court of Appeals determined that (i) the injection of fluids for the purpose of fracking constituted underground injection, (ii) all underground injection must be regulated, and, therefore, (iii) it was EPA's responsibility to regulate under the SDWA's UIC program. The EPAct 2005 clarified the SDWA to specify that the definition of "underground injection" *excludes* the injection of fluids or propping agents (other than diesel fuel) that are used in hydraulic fracturing related to oil, gas, or geothermal production activities.[4] The effect of this was to remove EPA's prior authority to regulate the underground injection of fluids, other than diesel fuel, used in hydraulic fracturing in order to protect ground and drinking water.

## § 29:210 Other Provisions

The EPAct 2005 is an expansive omnibus piece of legislation that addressed many other areas of energy utilization and growth outside the scope of this chapter,

[2] EPAct 2005 § 1504.

[3] EPAct 2005 § 1504, tit. XV, subtitle A.

[4] EPAct §§ 942, 1501(a).

**[Section 29:209]**

[1] Safe Drinking Water Act, 42 U.S.C. §§ 300f et seq. (1974).

[2] 40 C.F.R. § 144 (2021).

[3] Legal Environmental Assistance Foundation, Inc. v. U.S. E.P.A., 118 F.3d 1467, 1473, 45 Env't. Rep. Cas. (BNA) 1033, 27 Envtl. L. Rep. 21385, 139 O.G.R. 175 (11th Cir. 1997).

[4] EPAct 2005 § 322.

including the following: nuclear energy development and security,[1] including amendments to the Price-Anderson Act;[2] electricity;[3] energy policy tax incentives;[4] and climate change matters focusing on technology development and deployment.[5]

## C. ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

### § 29:211 Background and Purpose

The Energy Independence and Security Act (EISA) of 2007[1] came quickly on the heels of passage of the EPAct 2005. EISA is another omnibus energy policy law promulgated to increase energy efficiency and the availability of renewable energy.[2] Where the EPAct 2005 was sweeping legislation that included a heavy focus on the oil and gas industry, EISA took a forward-looking approach to address renewable fuels and innovations.

The key provisions of the EISA achieve the following: (i) changes to the Corporate Average Fuel Economy (CAFE) Standards;[3] discussed in Section § 29:213 below; (ii) creation of appliance and lighting efficiency standards,[4] discussed in Section § 29:214; and (iii) expansion of the Renewable Fuel Standard program that was created under the EPAct 2005,[5] discussed in Section § 29:216 below.

Two proposed provisions were never enacted into law due to their controversy in the legislature.[6] First was the Renewable Energy Portfolio Standard (RPS), which would have required electric utilities selling electricity in retail markets to provide a minimum amount of their electricity from renewable fuel sources or meet that requirement by purchasing an equal amount of tradeable credits. The minimum requirement was set to be a percentage share of the electric supplier's total retail electricity sales.

The second provision that was never enacted focused on energy tax subsidies. As proposed, the tax provisions were set to repeal about $22 billion of federal oil and gas subsidies in order to offset the cost of renewable energy and energy efficiency tax incentives included in the EISA. The final version of the EISA that was passed included tax revenue offsets large enough to cover the estimated cost of the CAFE standards, discussed in Section § 29:213 below, but the proposed repeal of the $22 billion in federal oil and gas subsidies was not in the final legislation.

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**[Section 29:210]**

[1] EPAct 2005 § 322, tit. VI.

[2] 42 U.S.C. § 2210. The Price-Anderson Act was enacted in 1957 to address public liability claims for personal injury and property damage in the event of a commercial nuclear power plant disaster.

[3] EPAct 2005 § 322, tit. XII.

[4] EPAct 2005 § 322, tit. XIII.

[5] EPAct 2005 § 322, tit. XVI.

**[Section 29:211]**

[1] Energy Independence and Security Act of 2007, Pub. L. No. 110-140, 121 Stat 1492.

[2] Pub. L. No. 110-140, 121 Stat 1492.

[3] Pub. L. No. 110-140, 121 Stat 1492, tit. I, subtitle A.

[4] Pub. L. No. 110-140, 121 Stat 1492, tit. III.

[5] Pub. L. No. 110-140, 121 Stat 1492, tit. II, subtitle A.

[6] For a detailed discussion of these two provisions not enacted into the EISA and the legislative history leading to those exclusions, *see* Fred Sissine, CONG. RSCH. SERV., RL34294, *Energy Independence and Security Act of 2007: A Summary of Major Provisions* (2008); Fred Sissine, CONG. RSCH. SERV., RL34116, *Renewable Energy Portfolio Standard (RPS): Background and Debate Over a National Requirement* (2007); Salvatore Lazzari, CONG. RSCH. SERV., RL33578, *Energy Tax Policy: History and Current Issues* (2008); Fred Sissine, CONG. RSCH. SERV., RL34162, *Renewable Energy: Background and Issues for the 110th Congress* (2008).

## § 29:212 Improved Vehicle Fuel Economy; Title I

The EISA fundamentally restructured the country's automotive fuel economy program and made significant changes to the CAFE Standards. The CAFE Standards set fuel economy averages that must be met for each model year of a vehicle. The purpose of the CAFE Standards, as set up by Congress at the time of enactment in 1975, was to reduce energy consumption by increasing the fuel economy of both cars and light trucks. In order to do this, Congress created a program to establish industry wide averages that each manufacturer must meet for each vehicle in its fleet, beginning in 1978. The CAFE standards were originally crafted under the EPCA,[1] with the National Highway Traffic and Safety Administration (NHTSA) setting and enforcing the standards and EPA calculating the average fuel economy levels.

The EISA changes to the CAFE Standards included a few parts. First, the EISA set a single CAFE standard of 35 miles per gallon by 2020, with interim standards beginning in 2011.[2] Additionally, manufacturers were required to be within 92% of the standard for each given model year.[3] However, the EISA established a credit system to allow manufacturers to purchase credits in order to reach compliance. These credits did not have a set expiration date, but the use of credits for compliance was required to be phased out by model year 2020 automobiles.[4] Manufacturers can buy and sell these credits amongst themselves, or alternatively, an individual manufacturer can exceed the CAFE Standard for one vehicle class and apply the exceedance (with limitations) to another of that manufacturer's vehicle class that may be short of compliance.[5]

## § 29:213 Other Energy Efficiency Measures; Titles III and IV

The EISA set new standards to reduce energy use and increase energy efficiency for a variety of appliances and lighting, including dishwashers, refrigerators, freezers, residential boilers, heating and air conditioning, incandescent lamps, and lamp fixtures.[1] The EISA also provides for energy savings in industry buildings.[2]

## § 29:214 Carbon Capture & Sequestration; Title VII

The EISA amended the EPAct 2005 to expand research and development into carbon capture and sequestration (CCS).[1] The section dedicated to CCS increased DOE's funding for research and development. DOE was also required to coordinate with the National Academy of Sciences to jointly update and review DOE's research and development programs around CCS.[2] There were also various provisions directing the Department of the Interior to focus their research into the ability to sequester carbon geologically and ways to utilize ecosystems to reduce emissions of

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**[Section 29:212]**

[1] Energy Policy and Conservation Act of 1975, Pub. L. No. 94-163, 89 Stat. 871.

[2] EISA §§ 102(b)(2)(A), 104.

[3] EISA § 102(b)(4)(B).

[4] EISA § 104(a)(2).

[5] EISA § 104(a)(2).

**[Section 29:213]**

[1] EISA § 104(a)(2), tit. III.

[2] EISA tit. IV.

**[Section 29:214]**

[1] EISA § 702.

[2] EISA § 702, tit. VII, subtitle B.

various pollutants, including carbon dioxide, methane and nitrous oxides.[3] Thus far, CCS has not been adopted widely due to comparatively high costs (making generation from facilities using CCS uneconomic) and a lack of federal and state government incentives comparable to renewable resources like wind and solar.

### D. RENEWABLE FUEL STANDARD, TITLE II, SUBTITLE A

### § 29:215 Historical Setting

In 2005, Congress established the Renewable Fuel Program under § 1501 of the EPAct 2005 to increase the use of renewable fuels in gasoline consumed in the United States. Congress charged EPA with implementing and enforcing the program.[1] Accordingly, EPA promulgated regulations implementing the first rendition of the Renewable Fuel Standard (commonly referred to as the "RFS1") in April 2007 to ensure that the pool of gasoline sold in the contiguous 48 states contained specific volumes of renewable fuel for each calendar year. This started with 4 billion gallons of renewable fuel in 2006, ramping up to 7.5 billion gallons by 2012.[2]

The RFS1 established compliance standards for refiners and importers of gasoline, a credit system based on renewable identification numbers (RINs) that could be verified and traded for compliance, an exemption from the RFS for small refineries, and general waiver provisions. EPA anticipated the RFS1 would reduce dependence on foreign sources of oil, increase domestic energy security, and reduce carbon dioxide emissions that contribute to climate change and air toxics emissions such as benzene.[3]

On December 19, 2007, two years after Congress enacted the EPAct 2005 and less than one year after EPA promulgated the RFS1 regulations, the EISA superseded the RFS1 and greatly expanded the RFS program.[4] EPA issued its final rule to implement and administer the expanded program (referred to as the "RFS2") on February 3, 2010. The RFS2 sets a target of 9 billion gallons of biofuels blended into transportation fuel in 2008, increasing to 36 billion gallons in 2022. After 2022, EPA must conduct annual rulemakings to determine the volumes of biofuels to be used in transportation fuel.

In addition to the expanded volumes and extended date, the RFS2 modifies the RFS1 in other significant ways. Unlike the RFS1, which limited renewable fuel blending requirements to gasoline, the RFS2 expands the scope of the program to apply to additional types of transportation fuel, most notably diesel.[5] The RFS2 also redefines renewable fuel to include subcategories, assigns a separate volume requirement to each category of fuel, and requires that renewable fuels qualifying under each category must achieve certain minimum thresholds of lifecycle greenhouse gas (GHG) emission reductions.[6] Further, the RFS2 provides EPA with an expanded

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[3]EISA § 702, tit. VII, subtitle B.

**[Section 29:215]**

[1]Pub. L. No. 109-58. Section 1501 of the EPAct 2005 amended the Clean Air Act and provides the statutory basis for the RFS in Section 211(o); U.S. EPA, Regulation of Fuels and Fuel Additives: Renewable Fuel Standard Program, 72 Fed. Reg. 23900, 23900 (May 1, 2007) (RFS1 final rule).

[2]40 C.F.R. § 80 Subpart K (2021).

[3]U.S. EPA, Regulation of Fuels and Fuel Additives: Renewable Fuel Standard Program, 72 Fed. Reg. 23900, 23900 (May 1, 2007) (RFS1 final rule).

[4]Pub. L. No. 110-140. The RFS1 regulations applied through June of 2010, and then the RFS2 regulations became effective on July 1, 2010.

[5]42 U.S.C. § 7545(o)(1)(L).

[6]42 U.S.C. § 7545(o)(2)(B).

waiver authority to lower RFS volumes.[7]

## E. THE CURRENT FRAMEWORK OF THE RENEWABLE FUEL STANDARD

### § 29:216 Renewable Fuel Categories and RINs

The RFS2 is the current regulatory framework under which obligated parties must comply.[1] The EISA provides a schedule of increasing volume mandates for four fuel categories—total renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel (BBD)—through 2022.[2] The four fuels categories are nested; total renewable fuel encompasses advanced biofuel (volume mandate specified in the statute) and conventional biofuel (no volume mandate specified in the statute); in turn, advanced biofuel encompasses cellulosic biofuel and BBD (both of which are specified in the statute), as well as "other advanced biofuels" (not specified in the statute). The volume of conventional biofuel is measured by taking the difference between the total renewable fuel volume and the advanced biofuel volume. The "other advanced biofuel" category is similarly measured by subtracting the cellulosic biofuel and BBD volumes from the total advanced biofuel volume.

To regulate compliance with the RFS, EPA uses a tradable credit system in which each gallon of renewable fuel produced for RFS compliance generates a certain number of credits, or RINs.[3] Each year, obligated parties—generally, refiners and importers of transportation fuel—incur a renewable volume obligation (RVO) for each fuel category, which is the obligated party's total gasoline and diesel sales multiplied by the annual renewable fuel percentage standard announced by EPA for that fuel category.[4] An obligated party's RVOs indicate the number of RINs the party must submit, or retire, in order to be in compliance with the RFS for a certain year.

Because the fuel categories are nested, cellulosic biofuel and BBD, or their RIN-equivalents, can be used to satisfy the advanced biofuel volume mandate and all three subcategories of fuels and RINs can be used to satisfy the total renewable fuel mandate. However, some biofuels generate more RINs per volume than others because of the difference in the fuel's energy content. For example, 1,000 physical gallons of ethanol (which qualifies as conventional biofuel) would equal 1,000 RIN gallons of biofuel, whereas 1,000 physical gallons of biodiesel would equal 1,500 RIN gallons of advanced biofuels.[5]

### § 29:217 Compliance with the RFS

EPA has identified refiners and importers of transportation fuels as the obligated parties under the RFS.[1] Thus refiners and importers must comply with the annual percentage standards adopted under the RFS. As discussed briefly in Section 29:216 above, obligated parties must retire RINs to EPA to meet their compliance

[7] 42 U.S.C. § 7545(o)(7).

**[Section 29:216]**

[1] The RFS2 is located at 40 C.F.R. pt. 80 Subpart M.

[2] *See* 42 U.S.C. § 7545(o)(1) for the statutory definitions of the fuel categories. Each fuel category must achieve certain GHG reductions relative to gasoline and diesel fuel.

[3] *See* 40 C.F.R. § 80.1426 (2021) for detail on how RINs are generated and assigned to batches of renewable fuel; *see* 40 C.F.R. § 80.1426 (2021) for detail on how RINs are used for compliance.

[4] EPA issues the percentage standards in its annual renewable volume rulemakings.

[5] *See* 40 C.F.R. § 80.1415 (2021) for more on equivalence values (EVs).

**[Section 29:217]**

[1] 40 C.F.R. § 80.1406 (2021).

obligation.[2] RINs have a two-year lifespan, meaning that they are only valid for use to demonstrate compliance in the year they are generated and the following year.[3]

If an obligated party cannot retire sufficient RINs to meet its RVOs for a given compliance year, the party can carry a deficit into the next year.[4] In the year following the deficit, the obligated party must meet compliance for that year's renewable fuel volume requirement and purchase or generate enough credits to satisfy the deficit from the previous year.[5] When an obligated party fails to either meet its RIN retirement obligations or carry a deficit, the party is in violation of the Clean Air Act and EPA has authority to bring an enforcement action.

### § 29:218 EPA's authority to waive or reset volume obligations

Although the EPAct 2005 and EISA set out mandatory minimum renewable volumes, Congress provided EPA with statutory authority to lower the annual volumes under certain circumstances. First, EPA has a general waiver authority, under which it can waive the scheduled total renewable fuel volume if implementation of the volume requirement would severely harm the economy or the environment or there is an inadequate domestic supply.[1] Second, EPA can waive the cellulosic biofuel mandate if the projected cellulosic biofuel production in a given year is less than the statutory volume.[2] Finally, EPA can waive the BBD mandate if a significant renewable feedstock disruption or other market circumstance would significantly increase the price of BBD.[3]

Under its cellulosic biofuel and BBD waiver authorities, EPA can reduce the total renewable fuel and advanced biofuel requirements by the same amount as it reduced either the cellulosic biofuel volume or BBD volume due to the way those fuel categories are nested. For example, in its final renewable volume rule for 2020, EPA announced that it was using its cellulosic biofuel waiver authority to reduce not only the cellulosic biofuel, but also the advanced biofuel and total renewable fuel volume requirements.[4] EPA must announce each year's renewable fuel volumes by November 30 of the previous year, with the exception of the BBD volume, which EPA must announce at least 14 months before the year in which it will apply.[5]

After 2015, if EPA waives the statutory volumes for any of the four fuel categories (total renewable, advanced biofuel, cellulosic biofuel, or BBD) by at least 20% for two consecutive years or by at least 50% for a single year, then EPA must modify, or reset, the statutory volumes for all subsequent years for that fuel type.[6] The reset provision has been triggered by EPA's use of its cellulosic waiver authority every year from 2016 to 2020. However, EPA has yet to reset statutory volumes for any

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[2] *See* 40 C.F.R. § 80.1427 (2021).

[3] 40 C.F.R. § 80.1427(a)(6)(i) (2021). The EPA Moderated Transaction System (EMTS) is used to register RIN transactions.

[4] 40 C.F.R. § 80.1427(b) (2021).

[5] 40 C.F.R. § 80.1427(b) (2021).

**[Section 29:218]**

[1] 42 U.S.C. § 7545(o)(7)(A).

[2] 42 U.S.C. § 7545(o)(7)(D).

[3] 42 U.S.C. § 7545(o)(7)(E). Note that the RFS program only provides statutory BBD volumes up to 2012, not 2022. This means that EPA no longer needs to use its BBD waiver authority, because there are no more statutory volumes to waive. Thus, EPA determines BBD volumes each year independent of its various waiver authorities.

[4] U.S. EPA, Renewable Fuel Standard Program: Standards for 2020 and Biomass-Based Diesel Volume for 2021 and Other Changes, 85 Fed. Reg. 7016 (Feb. 6, 2020).

[5] 42 U.S.C. § 7545(o)(3)(B)(i) to (ii).

[6] 42 U.S.C. § 7545(o)(7)(F).

fuel type.[7]

## § 29:219 Small refinery relief from the RFS

The EPAct 2005 exempted small refineries from compliance with the RFS from 2007 through 2010.[1] EPA extended the initial blanket exemption for certain small refineries for an additional two years, through 2012, based on a study commissioned by Congress and conducted by the Department of Energy (DOE).[2] In its study, DOE determined that certain small refineries would suffer a "disproportionate economic hardship" if required to participate in the program. Small refineries can also petition EPA "at any time" for an exemption from the RFS mandate due to disproportionate economic hardship.[3] When deciding whether to grant an exemption, EPA must consult with the Secretary of Energy, which takes the form of a recommendation from DOE to EPA.[4] By statute, the EPA Administrator has 90 days to act on a petition.[5]

## § 29:220 Current Trends

In recent years, a variety of factors contributed to changes in the landscape of oil and gas in the United States. For LNG export terminals, growth has slowed due to changes in economics and a downward trend in global demand. This trend continued through 2020 and the beginning of 2021, particularly due to low global gas prices, stiff competition from Australia for Asia-based LNG markets, and the COVID-19 pandemic.[1] Many of the recent planned and FERC-approved LNG terminals in the past few years are expansions of existing terminals, rather than new terminals.[2]

With respect to the more traditional oil and gas companies, there has been a push to diversify to establish a more sustainable footprint, even among oil majors. A fac-

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[7]EPA submitted a draft proposal to reset the statutory volumes for the 2020–2022 compliance years to the Office of Management and Budget in May 2019. In December of the same year, EPA withdrew its draft proposal. OFF. OF INFO. & REGUL. AFFS., *OIRA Conclusion of EO 12866 Regulatory Review*, https://www.reginfo.gov/public/do/eoDetails?rrid=129140 (last visited June 30, 2021). EPA has not indicated how it will address the reset requirement moving forward.

**[Section 29:219]**

[1]42 U.S.C. § 7545(o)(9)(A)(i). A small refinery is defined as "a refinery for which the average aggregate daily crude oil throughput for a calendar year (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels." 42 U.S.C. § 7545(o)(1)(K).

[2]U.S. DOE, SMALL REFINERY EXEMPTION STUDY: AN INVESTIGATION INTO DISPROPORTIONATE ECONOMIC HARDSHIP (2011), *available at* https://www.epa.gov/sites/production/files/2016-12/documents/small-refinery-exempt-study.pdf.

[3]42 U.S.C. § 7545(o)(9)(A)(ii)(II), (B)(i); 40 C.F.R. § 80.1441(e)(2) (2021).

[4]42 U.S.C. § 7545(o)(9)(B)(ii).

[5]42 U.S.C. § 7545(o)(9)(B)(iii); 40 C.F.R. § 80.1441(e)(2)(ii) (2021); EPA "will issue a decision within 90 days of receiving complete supporting information for the request from the small refinery." U.S. EPA, R*enewable Fuel Standard Exemptions for Small Refineries*, https://www.epa.gov/renewable-fuel-standard-program/renewable-fuel-standard-exemptions-small-refineries (last visited June 30, 2021).

**[Section 29:220]**

[1]For detailed data on natural gas and other fuels, *see* post from Victoria Zaretskaya, *U.S. liquified natural gas exports have declined by more than half so far in 2020*, U.S. ENERGY INFO. ADMIN., (June 23, 2020), https://www.eia.gov/todayinenergy/detail.php?id=44196 (last visited June 30, 2021).

[2]FED. ENERGY REGUL. COMM'N, LNG MAPS EXPORTS (Nov. 2, 2020), https://www.ferc.gov/media/lng-maps-exports; *see also U.S. LNG exports will return to pre-Covid levels by November 2020 as series of monthly increases begins*, LNG JOURNAL, (Sept. 10, 2020) *available at* https://lngjournal.com/index.php/latest-news-mainmenu-47/item/101055-us-lng-exports-will-return-to-pre-covid-levels-by-november-2020-as-series-of-monthly-increases-begins.

tor of this drive has been pressure from abroad—namely, among European-based oil and gas companies that are working to incorporate more green energies into their business model.[3] Another factor is the emphasis on clean energy and renewables as a driving point of the Biden administration.[4] The Biden administration has emphasized addressing methane and other chemical leaks from abandoned oil and gas wells, working with American growers instead of just oil lobbyists, and moving towards a carbon-pollution free power sector by 2035.[5]

The RFS, which in recent years has been the subject of intense political debate and scrutiny, stands to undergo significant change, affecting obligated parties (e.g., refineries and fuel importers) and others (e.g., renewable fuel producers and downstream blenders) alike. Stakeholders and politicians have placed a spotlight on small refinery exemptions and, in January 2020, a decision from the United States Court of Appeals for the Tenth Circuit further escalated the debate when the court ordered EPA to revoke extensions of the small refinery exemption it granted to three small refineries for the 2016 and 2017 compliance years because the small refineries had not received extensions every year since the beginning of the program.[6] On June 25, 2021, the United States Supreme Court reversed the lower court's decision, holding that the Clean Air Act does not require a refinery to receive an exemption for all prior years to remain eligible for future exemptions.[7]

Another hot button issue under the RFS is EPA's promulgation of annual renewable fuel volume targets. Stakeholders have challenged EPA's annual rulemakings as setting the renewable volumes both too high and too low. Currently, the 2020 renewable volumes rule is under judicial review in the United States Court of Appeals for the District of Columbia Circuit.[8] EPA has not yet issued the 2021 and 2022 renewable fuel volumes rules, which EPA was required by statute to promulgate by November 30, 2020 and November 30, 2021, respectively. It is anticipated that EPA will promulgate the 2021 and 2022 renewable fuel volumes rules-and adjust the 2020 rule-in a single rulemaking that has yet to be released. However, how the Biden administration will approach these annual rulemakings is unknown as of the time of publication.

Growth in the hydrogen sector may be poised to take off in the coming years. The EPAct 2005 included language directing the Secretary of Energy to coordinate research and development into hydrogen energy with the goal of further hydrogen production and hydrogen pipelines.[9] This has not yet taken off, but research into hydrogen fuel has been ongoing and will likely grow given the various pressures on companies, discussed above, to invest in more clean energy. With a potential growth in hydrogen fuel production, it is likely that issues will arise concerning the scope of FERC's regulatory authority. The extent of FERC's regulatory authority, if any, over pure-hydrogen interstate pipelines and gas quality standards in already FERC-regulated pipelines where producers may try blending hydrogen into the natural gas stream for transport remains to be seen.

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[3] Nick Butler, *How oil majors bought into green energy*, FIN. TIMES, July 15, 2020, *available at* https://www.ft.com/content/a7901eae-411e-43d0-8103-1f3c8d3a990c.

[4] Exec. Order No. 14008, 86 Fed. Reg. 7619 (Jan. 27, 2021), *available at* https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/.

[5] JoeBiden.com, *The Biden Plan to Build a Modern, Sustainable Infrastructure and an Equitable Clean Energy Future*, https://joebiden.com/clean-energy/ (last visited June 30, 2021).

[6] Renewable Fuels Ass'n v. U.S. EPA, 948 F.3d 1206, 1217 (10th Cir. 2020), rev'd sub nom. HollyFrontier Cheyenne Ref., LLC v. Renewable Fuels Ass'n, 141 S. Ct. 2172 (2021).

[7] HollyFrontier Cheyenne Ref., LLC v. Renewable Fuels Ass'n, 141 S. Ct. 2172 (2021).

[8] RFS Power Coalition v. EPA, et al., No. 20-1046 (D.C. Cir. 2020).

[9] EPAct tit. VIII.