Designation: D8011 – 17

Standard Specification for Natural Gasoline as a Blendstock in Ethanol Fuel Blends or as a Denaturant for Fuel Ethanol[1]

This standard is issued under the fixed designation D8011; the number immediately following the designation indicates the year of original adoption or, in the case of revision, the year of last revision. A number in parentheses indicates the year of last reapproval. A superscript epsilon (ε) indicates an editorial change since the last revision or reapproval.

1. Scope*

1.1 This specification covers natural gasoline to be used as a hydrocarbon blendstock in ethanol fuel blends for flexible-fuel automotive spark-ignition engines (Specification D5798). In the United States, these blends are referred to commercially as Ethanol Flex Fuel.

1.2 This specification also covers natural gasoline to be used as a denaturant in denatured fuel ethanol for blending with gasolines for use as automotive spark-ignition engine fuel (Specification D4806).

1.3 Specific regulatory requirements for the intended uses from various jurisdictions are given in appendixes for information.

1.4 This specification is not intended to provide a market specification nor a regulatory reference for natural gasoline for any use other than as a hydrocarbon blendstock in ethanol fuel blends or as a denaturant in denatured fuel ethanol.

1.5 The values stated in SI units are to be regarded as standard.

1.5.1 *Exception*—Values given in parentheses are provided for information only.

2. Referenced Documents

2.1 *ASTM Standards:*[2]

D86 Test Method for Distillation of Petroleum Products and Liquid Fuels at Atmospheric Pressure

D287 Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)

D381 Test Method for Gum Content in Fuels by Jet Evaporation

D1266 Test Method for Sulfur in Petroleum Products (Lamp Method)

D2622 Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry

D3120 Test Method for Trace Quantities of Sulfur in Light Liquid Petroleum Hydrocarbons by Oxidative Microcoulometry

D4052 Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter

D4057 Practice for Manual Sampling of Petroleum and Petroleum Products

D4175 Terminology Relating to Petroleum Products, Liquid Fuels, and Lubricants

D4176 Test Method for Free Water and Particulate Contamination in Distillate Fuels (Visual Inspection Procedures)

D4177 Practice for Automatic Sampling of Petroleum and Petroleum Products

D4306 Practice for Aviation Fuel Sample Containers for Tests Affected by Trace Contamination

D4806 Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel

D4814 Specification for Automotive Spark-Ignition Engine Fuel

D4953 Test Method for Vapor Pressure of Gasoline and Gasoline-Oxygenate Blends (Dry Method)

D5191 Test Method for Vapor Pressure of Petroleum Products (Mini Method)

D5453 Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence

D5482 Test Method for Vapor Pressure of Petroleum Products (Mini Method—Atmospheric)

D5580 Test Method for Determination of Benzene, Toluene, Ethylbenzene, *p/m*-Xylene, *o*-Xylene, C_9 and Heavier Aromatics, and Total Aromatics in Finished Gasoline by Gas Chromatography

D5798 Specification for Ethanol Fuel Blends for Flexible-Fuel Automotive Spark-Ignition Engines

D5842 Practice for Sampling and Handling of Fuels for Volatility Measurement

D5854 Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products

---

[1] This specification is under the jurisdiction of ASTM Committee D02 on Petroleum Products, Liquid Fuels, and Lubricants and is the direct responsibility of Subcommittee D02.A0 on Gasoline and Oxygenated Fuels.

Current edition approved Jan. 1, 2017. Published February 2017. Originally approved in 2016. Last previous edition approved in 2016 as D8011 – 16. DOI: 10.1520/D8011-17.

[2] For referenced ASTM standards, visit the ASTM website, www.astm.org, or contact ASTM Customer Service at service@astm.org. For *Annual Book of ASTM Standards* volume information, refer to the standard's Document Summary page on the ASTM website.

***A Summary of Changes section appears at the end of this standard**

D6378 Test Method for Determination of Vapor Pressure (VP_X) of Petroleum Products, Hydrocarbons, and Hydrocarbon-Oxygenate Mixtures (Triple Expansion Method)
D6469 Guide for Microbial Contamination in Fuels and Fuel Systems
D6550 Test Method for Determination of Olefin Content of Gasolines by Supercritical-Fluid Chromatography
D6730 Test Method for Determination of Individual Components in Spark Ignition Engine Fuels by 100–Metre Capillary (with Precolumn) High-Resolution Gas Chromatography
D6920 Test Method for Total Sulfur in Naphthas, Distillates, Reformulated Gasolines, Diesels, Biodiesels, and Motor Fuels by Oxidative Combustion and Electrochemical Detection
D7039 Test Method for Sulfur in Gasoline, Diesel Fuel, Jet Fuel, Kerosine, Biodiesel, Biodiesel Blends, and Gasoline-Ethanol Blends by Monochromatic Wavelength Dispersive X-ray Fluorescence Spectrometry
D7096 Test Method for Determination of the Boiling Range Distribution of Gasoline by Wide-Bore Capillary Gas Chromatography
D7220 Test Method for Sulfur in Automotive, Heating, and Jet Fuels by Monochromatic Energy Dispersive X-ray Fluorescence Spectrometry
D7347 Test Method for Determination of Olefin Content in Denatured Ethanol by Supercritical Fluid Chromatography
D7576 Test Method for Determination of Benzene and Total Aromatics in Denatured Fuel Ethanol by Gas Chromatography
D7667 Test Method for Determination of Corrosiveness to Silver by Automotive Spark-Ignition Engine Fuel—Thin Silver Strip Method
D7671 Test Method for Corrosiveness to Silver by Automotive Spark–Ignition Engine Fuel–Silver Strip Method
D7757 Test Method for Silicon in Gasoline and Related Products by Monochromatic Wavelength Dispersive X-ray Fluorescence Spectrometry

2.2 *Canadian National Standards:*[3]

CAN/CGSB-3.512 Automotive Ethanol Fuel (E50-E85)
CAN/CGSB 3.516 Denatured Fuel Ethanol for Use in Automotive Spark Ignition Fuels
CAN/CGSB 3.0 No. 60.32 Standard Test Method for the Determination of Corrosiveness to Silver of Gasoline, Middle Distillate Fuels and Oxygenated Fuels using Silver Wool: Rapid Ultrasonic Method

2.3 *Government Regulations:*

CFR Title 40, Part 79 Registration of Fuels and Fuel Additives[4]
CFR Title 40, Part 80 Regulation of Fuels and Fuel Additives[4]
CFR Title 27, Part 19 Distilled Spirits Plants[4]
CFR Title 27, Part 20 Distribution and Use of Denatured Alcohol and Rum[4]
CFR Title 27, Part 21 Formulas for Denatured Alcohol and Rum[4]
CCR Title 13 § 2260-§2298, California Code of Regulations[5]

3. Terminology

3.1 For general terminology, refer to Terminology D4175.

NOTE 1—The user is advised that the definitions used by various industries, marketers, and regulatory bodies can differ from those specific to this specification. It is the responsibility of the user to ensure that the terms used in a particular context are clearly understood. Appendix X7 contains additional information for a number of these terms.

3.2 *Definitions:*

3.2.1 *dry vapor pressure equivalent (DVPE), n*—value calculated by a defined correlation equation that is expected to be comparable to the vapor pressure value obtained by Test Method D4953, Procedure A. **D4953**

3.2.2 *natural gasoline, n*—a hydrocarbon blend composed predominately of molecules with 5 to 8 carbon atoms and typically separated from the production flows from natural gas wells or crude oil wells.

3.2.2.1 *Discussion*—These hydrocarbon blends may be processed to further remove lighter or heaver hydrocarbons or reduce sulfur content. Other names for this blend include naphtha and field naphtha.

3.2.2.2 *Discussion*—Different government regulations may define "natural gasoline" in different ways. Refer to specific regulations.

3.3 *Abbreviations:*

3.3.1 CARB—California Air Resources Board

3.3.2 CFR—U.S. Code of Federal Regulations

3.3.3 CGSB—Canadian General Standards Board

3.3.4 DVPE—Dry Vapor Pressure Equivalent

3.3.5 EFB—Ethanol Fuel Blend

3.3.6 EPA—The U.S. Environmental Protection Agency

3.3.7 TTB—Alcohol and Tobacco Tax and Trade Bureau of the U.S. Department of Treasury

3.3.8 U.S.—United States of America

4. Performance Requirements

4.1 See Table 1.

5. Regulatory Requirements

5.1 Natural gasoline shall meet the performance requirements in Table 1. It will also need to meet additional limits related to the regulatory requirements of the authority having jurisdiction for regulating denaturants and hydrocarbon blendstocks. The hydrocarbons used as denaturants to produce

[3] Canadian fuel standards are available from Canadian General Standards Board: CGSB Sales Centre Gatineau, Canada K1A 1G6; web site: http://www.techstreet.com/cgsb/subgroups/13684.

[4] A printed copy of the Code of Federal Regulations may be purchased from the U.S. Government Printing Office Superintendent of Documents, 732 N. Capitol St., NW, Mail Stop: SDE, Washington, DC 20401 or the online store at http://bookstore.gpo.gov/. The Code of Federal Regulations may be browsed online at http://www.gpoaccess.gov/cfr/index.html.

[5] California regulations are available online at http://government.westlaw.com.

TABLE 1 Performance Requirements

Properties/Use of Natural Gasoline	Denaturant for Denatured Fuel Ethanol[A,B]	Hydrocarbon Blendstock for Ethanol Fuel Blends[C]	Test Methods
Density, kg/m^3 at 15 °C, or	Report	Report	D4052
API gravity	Report	Report	D287
Dry Vapor Pressure Equivalent, at 37.8 °C (100 °F), kPa (psi)	Report	Report[D,E]	D4953, D5191, D5482, D6378
Distillation Temperature, End point (or Final Boiling Point), °C (°F), max	225 (437)	225 (437)	D86,[F] D7096
Silver corrosion, max		No. 1	D7667, D7671, CAN/CGSB 3.0 No. 60.32[G]
Sulfur, mg/kg	Report	Report	D1266, D2622, D3120, D5453, D6920, D7039, or D7220
Unwashed Gum, mg/100 mL	Report	Report	D381
Solvent washed gum, max, mg/100 mL	Report	5	D381

[A] Natural gasoline intended for use as a denaturant in denatured fuel ethanol meeting the requirements in Specification D4806. See Section 5 for regulatory requirements related to natural gasoline used to produce denatured fuel ethanol.
[B] See U.S. EPA 40 CFR 80.47 for Performance-Based Analytical Test Method Approach requirements for analytical reporting and validation.
[C] Natural gasoline intended for use as a hydrocarbon blendstock in ethanol fuel blends meeting the requirements in Specification D5798. See Section 5 for regulatory requirements related to natural gasoline used to produce ethanol fuel blends.
[D] The vapor pressure of the natural gasoline used as the hydrocarbon blendstock to produce ethanol fuel blends shall be such that seasonal and geographical limits as outlined in Tables 1 and 3 of Specification D5798 are met. Specification D5798 fuel blend vapor pressure ranges from 38 kPa (5.5 psi) to 103 kPa (15.0 psi). The vapor pressure of the blend is a function of the vapor pressure of the hydrocarbon blendstock and the content of ethanol in the blend which can range from 51 % to 83 % by volume.
[E] Users of natural gasoline may have limits on dry vapor pressure equivalent related to the storage tanks used and environmental permitting of the storage tanks.
[F] Test Method D86 does not include natural gasoline in its scope and can provide highly variable results for low boiling point materials. Test Method D86 is considered appropriate for determination of the final boiling point of natural gasoline. Test Method D7096 will work for lower boiling point materials but an ASTM standard correlation between Test Method D86 and Test Method D7096 has not been developed, see 7.1.1.1.
[G] See 7.1.2 for equivalent limits using CAN/CGSB-3.0 No. 60.32.

denatured fuel ethanol and as hydrocarbon blendstock used to produce ethanol fuel blends are covered by regulations specific to a jurisdiction or by multiple regulations due to overlapping jurisdictions. Appendixes have been developed to provide information for several jurisdictions describing the requirements for products and activities within the designated jurisdiction:

5.1.1 Appendix X2: Regulatory Requirements for Canada.

5.1.2 Appendix X3: Regulatory Requirements for the United States.

5.1.3 Appendix X4: Regulatory Requirements for California. (See Appendix X3 and Appendix X4.)

5.1.4 Table X1.1 provides the limits established by relevant regulatory agencies for Canada, the United States and the State of California at the time of publication of this standard. Table X1.2 provides limits for parameters based on the regulatory requirements of U.S. and California regulatory agencies and possible usage scenarios in the marketplace.

5.2 Consult the appropriate regulatory agencies to confirm if hydrocarbons other than natural gasoline may be mixed with the natural gasoline to be used as a denaturant for denatured fuel ethanol or as a hydrocarbon blendstock for blending with denatured fuel ethanol to produce ethanol fuel blends. The use of hydrocarbons other than natural gasoline can result in parameter limits other than the values in these tables to maintain compliance with the jurisdictional regulations.

5.3 Other agencies or jurisdictions not listed may also establish additional requirements for natural gasoline used as the denaturant in denatured fuel ethanol or as the hydrocarbon blendstock in ethanol fuel blends. The user of this standard is responsible for consulting the jurisdiction where the denatured fuel ethanol and ethanol fuel blends will be produced and used to determine specific regulatory compliance requirements.

6. Workmanship

6.1 At the point of custody transfer, natural gasoline shall be visually free of sediment, undissolved water, and suspended matter. It shall be clear and bright at the fuel temperature at the point of custody transfer or at an alternative temperature agreed upon by the purchaser and seller. The product shall be free of any adulterant or contaminant that can render the material unacceptable for its commonly used applications.

NOTE 2—Test Method D4176 can be helpful for evaluating the product.

6.2 The specification defines only the basic requirements for natural gasoline. Buyers and sellers may agree upon more stringent requirements.

6.2.1 Producers and blenders of natural gasoline shall avoid natural gasoline contaminated by silicon-containing materials. Silicon contamination of gasoline, denatured ethanol, and their blends has led to fouled vehicle components (for example, spark plugs, exhaust oxygen sensors, catalytic converters) requiring parts replacement and repairs. Test Method D7757 is a procedure for determining silicon content that might be applicable to natural gasoline. No specification limits have been established for silicon.

6.2.2 Producers and blenders of natural gasoline shall avoid natural gasoline contaminated by any materials not composed of carbon, hydrogen, oxygen, nitrogen and sulfur (non-CHONS). There is concern that the limited processing received by some natural gasoline (in comparison to the processing received by gasoline blending components in conventional refining) could result in trace contaminants (for example, phosphorus, mercury, cyanides, and a long list of metallic elements) being present in natural gasoline that could deactivate catalytic converters on vehicles, resulting in undesirable emissions. Work is underway to identify possible non-CHONS contaminants in natural gasoline, and to determine if a suitable test method and limit can be developed.

6.2.3 The natural gasoline used as a denaturant in denatured fuel ethanol and as a hydrocarbon blendstock for ethanol fuel blends shall not contain materials which can separate from solution at the expected temperatures of blending, storage and use. If drag reducing agent (additive) (DRA) is used in the natural gasoline distribution system, it cannot be present in the product delivered to be used as a denaturant at a concentration or sheer condition which can separate from the denatured fuel ethanol under those conditions.

7. Test Methods

7.1 The requirements of this specification shall be determined in accordance with the methods listed below. Refer to the listed test methods to determine applicability or required modifications for use with natural gasoline. The scopes of some of the test methods below do not specifically include natural gasoline. The precision of these test methods can differ from the reported precisions when testing natural gasoline.

7.1.1 *Distillation*—Test Methods D86 and D7096.

7.1.1.1 Test Method D86 – 12 does not cover natural gasoline in the scope. Versions prior to Test Method D86 – 07 included natural gasoline in the scope. Natural gasoline normally contains very light hydrocarbons which can evaporate before the initial stages of the distillation and be lost, thus there would be a need for cold samples and careful apparatus preparation. By the time the distillation reaches ten percent evaporation, the distillation should be similar to the distillation of a typical gasoline sample. Test Method D86 should be applicable for the distillation points referenced in this specification after it is corrected for the front end loss. Test Method D7096 is a gas chromatographic test method that detects and measures low boiling point hydrocarbons, however an ASTM correlation between Test Methods D86 and D7096 has not been developed. Before converting Test Method D7096 results to predicted Test Method D86 values, a correlation shall be developed and agreed to by the seller, buyer, and appropriate regulatory agencies.

7.1.2 *Corrosion, for Silver*—Test Methods D7667, D7671, or CAN/CGSB-3.0 No. 60.32. A silver wool rating of 'B' maximum by CAN/CGSB-3.0 No. 60.32 would be equivalent to a silver strip rating of 'No. 1' maximum by Test Methods D7667 or D7671. Since silver is more susceptible to corrosion by aggressive sulfur species than copper, a passing result in a silver corrosion test is indicative that the sample would also pass a copper strip corrosion test.

7.1.3 *Sulfur*—Test Methods D1266, D2622, D3120, D5453, D6920, D7039, or D7220. With Test Method D3120, fuels with sulfur content greater than 100 mg/kg (0.0100 % by mass) shall be diluted with isooctane. The dilution of the sample can result in a loss of precision.

7.1.4 *Vapor Pressure (Dry Vapor Pressure Equivalent)*—Test Methods D4953, D5191, D5842, or D6378.

7.1.4.1 When using Test Method D6378, determine VP_4 at 37.8 °C (100 °F) using a sample from a 1 L container and convert to DVPE (Test Method D5191 equivalence) using the following equation:

$$\text{Predicted DVPE} = VP_{4\ 37.8\ °C} - 1.005\ \text{kPa} \tag{1}$$

$$\left(\text{Predicted DVPE} = VP_{4\ 100\ °F} - 0.15\ \text{psi}\right) \tag{2}$$

7.1.5 *Solvent-Washed Gum Content*—Test Method D381, air jet apparatus.

7.1.6 *Benzene*—Test Methods D5580, D6730.

8. Sampling, Containers, and Sample Handling

8.1 The reader is strongly advised to review all intended test methods prior to sampling to understand the importance and effects of sampling technique, proper containers, and special handling required for each test method.

8.2 Correct sampling procedures are critical to obtain a sample representative of the lot intended to be tested. Use appropriate procedures in Practice D4057 for manual method sampling and in Practice D4177 for automatic method sampling, as applicable, and note the guidance of Practice D5842 for sampling natural gasoline because of its high volatility.

8.3 The correct sample volume and appropriate container selection are important decisions that can impact test results. Refer to Practice D4306 for aviation fuel container selection for tests sensitive to trace contamination. Refer to Practice D5854 for procedures on container selection and sample mixing and handling. For octane number determination, protection from light is important. Collect and store sample fuels in an opaque container, such as a dark brown glass bottle, metal can, or minimally reactive plastic container to minimize exposure to UV emissions from sources such as sunlight or fluorescent lamps.

8.4 For volatility determination of a sample, refer to Practice D5842 for special precautions recommended for representative sampling and handling techniques.

9. Keywords

9.1 denaturant; denatured fuel ethanol; ethanol fuel blend; gasoline; natural gasoline

APPENDIXES

(Nonmandatory Information)

X1. REGULATORY AND RELATED REQUIREMENTS

X1.1 Appendix X1 contains both regulatory requirements and calculated values based on regulatory requirements for natural gasoline to be used as a denaturant in denatured fuel ethanol and as the hydrocarbon blendstock in ethanol fuel blends. While the following requirements are believed to be accurate at the time of publication, users should consult the relevant authority to confirm the current regulations and requirements. The information provided about the regulations is for information only. In case of conflict, the text of current regulations takes precedence.

X1.1.1 Table X1.1 contains information about relevant regulatory requirements for Canada, the United States, and the State of California at the time of publication of this standard.

X1.1.2 Table X1.2 provides limits for parameters based on the regulatory requirements of U.S. and California regulatory agencies and possible usage scenarios in the marketplace. These calculated values assume that only natural gasoline is being used as the denaturant or as the hydrocarbon blendstock. If other hydrocarbons are included, the values may no longer be appropriate.

TABLE X1.1 Regulatory Requirements Pertaining to Natural Gasoline Used as a Denaturant and Hydrocarbon Blendstock for Ethanol Fuel Blends

Properties	Denaturant			Hydrocarbon Blendstock for Ethanol Fuel Blends			Test Methods
Applicability	For use in Canada	For use in the U.S.^{A}	For use in California	For use in Canada	For use in the U.S.	For use in California	
Reference	See X2.2	See X3.2	See X3.2 and X4.2	See X2.3	See X3.3	See X3.3 and X4.3	
Distillation Temperatures, °C, (°F), at % Evaporated							D86, D7096
10 % by volume, min	35 (95)^{B}	36 (97)^{B}					
50 % by volume, max		69 (156)^{B}				100 (213)^{C}	
90 % by volume, max		98 (209)^{B}				152 (305)^{C}	
Sulfur, mg/kg, max		330^{D}					D1266, D2622, D3120,D5453, D6920, D7039, or D7220
Benzene, % by volume, max			1.1^{E}			1.10^{F}	D5580
Olefins, % by volume, max			10.0^{E}			10.0^{F}	D6550
Aromatics, % by volume, max			35.0^{E}			35.0^{F}	D5580

[A] See U.S. EPA 40 CFR 80.47 for Performance-Based Analytical Test Method Approach requirements for analytical reporting and validation.
[B] No specific test method is referenced in the Alcohol and Tobacco Tax and Trade Bureau (TTB) of the U.S. Treasury Department and Revenue Canada regulations. At the time the TTB and Revenue Canada limits were created, Test Method D86 was the standard test method for these parameters.
[C] Limits set by the California Air Resources Board (CARB) utilize Test Method D86 – 99.
[D] The U.S. EPA, effective January 1, 2017, establishes a limit of 330 ppm sulfur in denaturant. See X3.4.2.
[E] California regulations (Title 13 CCR 2262.9) establish limits of 1.10 % by volume benzene, 10.0 % by volume olefins, and 35.0 % by volume aromatics for the denaturant used to produce denatured fuel ethanol. The regulatory limits assume the maximum denaturant content of 5.00 % by volume is contained in the denatured fuel alcohol. The regulations allow the limits to be adjusted if lower denaturant concentrations are used.
[F] California regulations (Title 13 CCR 2292.4) sets a maximum content of benzene, olefins, and aromatics for the hydrocarbon blendstock used to produce ethanol fuel blends.

TABLE X1.2 Calculated Requirements Pertaining to Natural Gasoline Based on U.S. and California Regulations

Properties	Denaturant for Denatured Fuel Ethanol		Hydrocarbon Blendstock for Ethanol Fuel Blends (EFB)			Test Methods
Applicability	For use in the U.S. outside of California (U.S. grade)[A]	For use in California (CARB grade)	For use in the U.S. outside of California	For use in U.S. outside of California	For use in California	
Grade of Denatured Fuel Ethanol			U.S.	CARB	CARB	
Grade of Natural Gasoline	D1	D2	EFB1	EFB2	EFB3	
Assumption	Denaturant content, 2.5 % by volume, max	Denaturant content, 2.5 % by volume, max				
Sulfur, mg/kg, max	330[B]	400[C]	30[D]	53[E]	86[F]	D1266, D2622, D3120, D5453, D6920, D7039, or D7220
Benzene, % by volume, max	24.8[G]	2.2[H]	0.62[I]	1.2[J]		D5580 or D6730
Olefins, % by volume, max		20.0[H]				D6550 or D6730
Aromatics, % by volume, max		70.0[H]				D5580 or D6730

[A] See U.S. EPA 40 CFR 80.47 for Performance-Based Analytical Test Method Approach requirements for analytical reporting and validation.
[B] Effective January 1, 2017 the maximum sulfur content of certified denaturant will be 330 mg/kg (see X3.4.2).
[C] The California regulations set a sulfur limit of 10 mg/kg in the denatured fuel ethanol (Title 13 CCR 2262.9). Assume all sulfur originates with the denaturant, at a maximum denaturant content of 2.5 % by volume the limit for sulfur content in the denaturant would be 400 mg/kg.
[D] To compensate for the denaturant content in the denatured fuel ethanol, assume 53 % by volume denatured fuel ethanol is needed to obtain 51 % by volume ethanol. The ethanol fuel blend would contain a maximum of 47 % by volume natural gasoline. The current U.S. EPA annual average sulfur limit in spark-ignition engine fuels defined in Specification D4814 is 30 mg/kg. The current limit in Specification D4806 is 30 mg/kg (ppm by mass). The maximum sulfur content of the natural gasoline used as the hydrocarbon blendstock to produce ethanol fuel blends would be 30 mg/kg. (see X3.5.2.)
[E] To compensate for the denaturant content in the denatured fuel ethanol, assume 53 % by volume denatured fuel ethanol is needed to obtain 51 % by volume ethanol (Specification D5798). The ethanol fuel blend would contain a maximum of 47 % by volume natural gasoline. The sulfur limit in California compliant denatured fuel ethanol is 10 mg/kg (Title 13 CCR 2262.9). The current U.S. EPA annual average sulfur limit in spark-ignitions engine fuels defined by Specification D4814 is 30 mg/kg. The sulfur limit of the natural gasoline used as the hydrocarbon blendstock to produce ethanol fuel blends (Specification D5798 outside of California) would be 53 mg/kg. (see X3.5.2)
[F] California regulations (Title 13 CCR 2292.4) require 79 % by volume minimum ethanol content and a maximum sulfur content of 0.004 % by mass in ethanol fuel blends. To compensate for the denaturant content in the denatured fuel ethanol, assume 82 % by volume denatured fuel ethanol is needed to obtain 79 % by volume ethanol. The ethanol fuel blend would contain a maximum of 18 % by volume natural gasoline. The sulfur limit in California compliant denatured fuel ethanol is 10 mg/kg (Title 13 CCR 2262.9). The maximum sulfur content of the natural gasoline used as the hydrocarbon blendstock to produce California compliant ethanol fuel blends would be 86 mg/kg. (see X3.5.2)
[G] The U.S. EPA regulations (40 CFR 80.1230(a)(1)) set a maximum annual average benzene content of gasoline. Denaturant with a maximum benzene content of 24.8 % by volume when used at a maximum denaturant content of 2.5% by volume would produce a denatured fuel ethanol with a maximum benzene content of 0.62 % by volume.
[H] The California regulatory limits for denaturant are based on a maximum denaturant content of 5.00 % by volume in the denatured fuel alcohol. The regulations allow the limits to be adjusted if lower denaturant concentrations are used. See Table X4.2 for appropriate test methods.
[I] The U.S. EPA regulations limit the annual average benzene content in gasoline to a maximum of 0.62 % by volume. This limit for the natural gasoline used as the hydrocarbon blendstock to produce ethanol fuel blends assumes the denatured fuel ethanol in the blend will have a maximum benzene content equal to the maximum average annual benzene content for gasoline.
[J] California regulations (Title 13 CCR2262.9) limit the benzene content in denatured fuel ethanol to 0.06 % by volume. Natural gasoline used as the hydrocarbon blendstock with a maximum benzene content of 1.2 % by volume would produce an ethanol fuel blend with a maximum benzene content equal to the annual average benzene standard for gasoline of 0.62 % by volume (40 CFR 80.1230(a)(1)).

X2. REGULATORY REQUIREMENTS FOR CANADA

X2.1 Applicable Jurisdiction

X2.1.1 The requirements of Appendix X2 apply to natural gasoline used as a denaturant if denatured fuel ethanol or as the hydrocarbon blendstock in ethanol fuel blends that are produced, imported or used in Canada.

X2.2 Information Related to Denaturants in Canada

X2.2.1 In Canada, denaturants and denaturant formulas are approved by Revenue Canada. See CAN/CGSB 3.516 for a discussion of denaturant requirements in Canada.

X2.3 Information Related to Hydrocarbon Blendstock in Ethanol Fuel Blends in Canada

X2.3.1 The Canadian regulations related to ethanol fuel blends are found in CGSB specification CAN/ CGSB-3.512.

X3. REGULATORY REQUIREMENTS FOR THE UNITED STATES

X3.1 Applicable Jurisdiction

X3.1.1 The requirements of Appendix X3 apply to natural gasoline used as a denaturant in denatured fuel ethanol or as the hydrocarbon blendstock in ethanol fuel blends that are produced, imported or used in the United States.

X3.1.2 The U.S. EPA regulations establish requirements for fuels and fuel additives including natural gasoline used as a denaturant.

X3.1.2.1 The U.S. EPA regulations stipulate (40 CFR 80.1611(a)(2)) that the denatured fuel ethanol and thus the denaturant be composed solely of carbon, hydrogen, oxygen, nitrogen and sulfur.

X3.1.2.2 The regulations also address other physical and compositional characteristics.

X3.2 Information Related to Denaturants in the United States

X3.2.1 In the U.S., denaturants are approved by the Alcohol and Tobacco Tax and Trade Bureau (TTB) of the U.S. Treasury Department. The U.S. requirements for denaturants are found in 27 CFR Parts 19 and 21. The TTB uses the following description for natural gasoline: "Natural gasoline (drip gas) is a mixture of butane, pentane, and hexane hydrocarbons extracted from natural gas." These requirements are applicable in all areas of the U.S. The U.S. EPA regulations establish additional requirements for denatured fuel ethanol.

X3.2.2 The U.S. EPA limits denaturants for denatured fuel ethanol to be used as an oxygenate in gasoline (40 CFR 80.1610(a)(3)) to previously certified gasoline (including previously certified blendstocks for oxygenate blending), gasoline blendstocks or natural gas liquids.

X3.3 Regulatory Limits on Denaturant Content in the United States

X3.3.1 The minimum denaturant content for completely denatured fuel ethanol is set by the TTB at 1.96 % by volume. The current maximum denaturant content in the U.S. is 5 % by volume. The U.S. EPA has established the maximum denaturant content of denatured fuel ethanol for generation of renewable identification numbers (RIN) at less than 2.5 % by volume. The values in Table X1.2 for use in the U.S. outside of California are based on denaturant addition less than 2.5 % by volume. If denaturant is added at concentrations equal to or greater than 2.5 % by volume, the limits in must be adjusted accordingly.

NOTE X3.1—The U.S. EPA, effective January 1, 2017, has set a maximum denaturant content of 3.0 % by volume. A denaturant content for full RIN generation will remain at less than 2.5 % by volume.

X3.4 Characteristics of Natural Gasoline to be Used as a Denaturant in the United States

X3.4.1 The TTB establishes characteristics (and sources) for natural gasoline to be used as a denaturant for completely denatured fuel ethanol.

X3.4.2 The EPA establishes characteristics for natural gasoline to be used as a denaturant in denatured fuel ethanol. The current U.S. sulfur limit for denatured fuel ethanol is 30 ppm (40 CFR 80.385(e)(1)). Effective January 1, 2017, the "sulfur content ([of the denatured fuel ethanol] must not be greater than 10 ppm" and "the concentration of all denaturants used in DFE [denatured fuel ethanol] is limited to a maximum of 3.0 volume percent" (40 CFR 80.1610). For certified denaturants, the "sulfur content must not be greater than 330 ppm" and "the ethanol denaturant must be composed solely of carbon, hydrogen, nitrogen, oxygen and sulfur" (40 CFR 80.1611).

X3.5 Requirements for Natural Gasoline Used as the Hydrocarbon Blendstock in Ethanol Fuel Blends in the United States

X3.5.1 The U.S. EPA has established regulations for physical and compositional characteristics for fuels and fuel additives in the U.S. (40 CFR Parts 79 and 80).

X3.5.2 The U.S. EPA regulations require a maximum annual average sulfur content of spark-ignition engine fuels of 30 mg/kg. The calculated sulfur limits shown in Table X1.2 are based on a maximum sulfur content of 30 mg/kg for the ethanol fuel blends. There are currently no regulatory provisions for non-gasoline blendstocks to participate in the U.S. EPA sulfur averaging program. Gasoline blendstocks participating in the sulfur averaging program shall be used to produce ethanol fuel blends with a sulfur content between 30 mg/kg and 80 mg/kg.

X4. REQUIREMENTS FOR CALIFORNIA

X4.1 Applicable Jurisdiction

X4.1.1 The requirements of Appendix X4 apply to natural gasoline used as a denaturant in denatured fuel ethanol or as the hydrocarbon blendstock in ethanol fuel blends that are produced, imported or used in California. The U.S. EPA and TTB requirements (see Appendix X3) for denaturants are applicable in California. California regulations set limits on the physical and compositional characteristics of fuel and fuel additives that may be more restrictive than U.S. EPA limits.

X4.2 Information Related to Denaturants in California

X4.2.1 The California Air Resources Board has approved standards for denatured ethanol to be field-blended with California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) to make California Phase 3 Reformulated Gasoline (CaRFG3). Standards also have been specified for the denaturant. These California standards for denatured ethanol and denaturant became effective Dec. 31, 2003 and were amended on Aug. 29, 2008.

X4.2.2 The California standards for denatured ethanol set maximum limits on sulfur, benzene, olefins, and aromatics contents as shown in Table X4.1, and also require the denatured ethanol to comply with the performance requirements in Specification D4806 – 99.

X4.2.3 California specifies that compliance with the sulfur standard shall be determined by testing the denatured ethanol using Test Method D5453 – 93. California specifies that compliance with the standards for benzene, olefins, and aromatics contents may be determined by testing a sample of the denaturant using the test methods specified for CARB gasoline, and then calculating the content of those compounds in the denatured ethanol, multiplying the test value by 0.0500. However, where it is demonstrated that the denatured ethanol contains less than 5.00 % by volume denaturant, then the test results are multiplied by the decimal fraction representing the percent denaturant. See Title 13 California Code of Regulations § 2262.9.

X4.2.3.1 Starting February 16, 2014, California specifies an alternative method of compliance with the standards for the aromatic hydrocarbon and benzene content of denatured ethanol shall be determined by ASTM D7576 – 10 (2010). Starting February 16, 2014, an alternative method of compliance with the olefin content of denatured ethanol shall be determined by ASTM D7347 – $07^{\varepsilon 1}$ (2007). In the event of any discrepancy between results, the direct test methods shall take precedence.

X4.2.4 California allows an exception to the limits shown in Table X4.1 where the denatured ethanol supplier takes reasonably prudent precautions to ensure the denatured ethanol that exceeds these limits will only be added to a specially designed CARBOB which has been designated to be blended with such denatured ethanol. Documentation is required to support the transfer of denatured ethanol. All CaRFG3 requirements for the final blend shall be met.

X4.2.5 California specifies the standards for the denaturant used in denatured ethanol as shown in Table X4.2. Also shown are the test methods required to determine compliance.

X4.2.6 California standards allow higher amounts of benzene, olefins, and aromatics in the denaturant if the supplier takes necessary precautions to ensure that when added to the ethanol, the level is less than 5.00 % by volume and the limits in Table X4.1 are met.

X4.3 Information Related to Hydrocarbon Blendstock in Ethanol Fuel Blends in California

X4.3.1 The CARB limits for alternative fuels such as ethanol fuel blends are set in Title 13 CCR § 2292.4.

TABLE X4.1 California Denatured Ethanol Standards
(In Addition to the Performance Requirements in ASTM Specification D4806 – 99)

Property	Specification Limit	Test Method
Sulfur, mg/kg (ppm by mass), max	10	D5453 – 93
Benzene, % by volume, max	0.06	D7576 – 10
Olefins, % by volume, max	0.5	D7347 – $07^{\varepsilon 1}$
Aromatics, % by volume, max	1.7	D7576 – 10

TABLE X4.2 California Denaturant Standards

Property	Specification Limit	Test Method
Benzene, % by volume, max	1.10	D5580 – 02 (2007)
Olefins, % by volume, max	10.0	D6550 – 10
Aromatics, % by volume, max	35.0	D5580 – 02 (2007)

X5. SIGNIFICANCE OF ASTM SPECIFICATION FOR NATURAL GASOLINE

X5.1 Vapor Pressure

X5.1.1 The vapor pressure of fuel shall be sufficiently high to ensure ease of engine starting, but it shall not be so high as to contribute to vapor lock or excessive evaporative emissions and running losses.

X5.1.2 Test Methods D4953, D5191, D5482, or D6378 provide procedures for determining the vapor pressures of gasoline or gasoline-oxygenate blends.

X5.2 Distillation

X5.2.1 Test Method D86 for distillation is specified in some regulations, but the scope does not currently include highly volatile materials like natural gasoline. Table 1 designates the limits for end point (final boiling point) temperature and the temperatures at which 10 %, 50 %, and 90 % by volume of the fuel is evaporated. These distillation characteristics, along with vapor pressure, can affect the characteristics of the finished fuel. Test Method D86 results are highly variable for the low boiling materials (for example, 10 % and 50 % for natural gasoline)

X5.2.2 Test Method D7096 is a gas chromatographic method that is applicable to a material like natural gasoline. This test method is more appropriate for low boiling materials however there is no ASTM correlation between the two test methods. If Test Method D7096 results are to be converted to Test Method D86 results, a correlation between the two methods shall be developed and agreed to by the buyer, seller, and appropriate regulatory agencies.

X5.3 Corrosion

X5.3.1 Reactive sulfur compounds present in automotive spark-ignition engine fuel under some circumstances can corrode or tarnish silver and copper alloys. To minimize the failure of silver alloy in-tank sender units by corrosion or tarnish, fuels shall pass a silver strip corrosion test.

X5.4 Solvent-Washed Gum Content

X5.4.1 The test for solvent-washed gum content measures the amount of residue after evaporation of the fuel and following a heptane wash. The heptane wash removes the heptane-soluble, non-volatile material such as additives, carrier oils used with additives, and heavier hydrocarbons such as diesel fuels. Solvent-washed gum consists of heptane-insoluble gum. This portion of the gum is also insoluble in spark-ignition engine fuel (gasoline or gasoline-oxygenate blends) and can clog fuel filters. Both soluble and insoluble gum can be deposited on surfaces when the fuel evaporates, forming deposits.

X5.4.2 Solvent-washed gum can contribute to deposits on the surfaces of carburetors, fuel injectors, and intake manifolds, ports, valves, and valve guides. The impact of solvent-washed gum on malfunctions of modern engines is not well established and the current specification limit is historic rather than the result of recent correlative studies. It depends on where the deposits form; the presence of other deposit precursors, such as airborne debris, blowby and exhaust recirculation gases, and oxidized engine oil; and the amount of deposits.

X5.4.3 The difference between the unwashed and solvent washed gum content values can be used to assess the presence and amount of nonvolatile material in the fuel. Additional analytical testing is required to determine if the material is additive, carrier oil, diesel fuel, or other material.

X5.5 Sulfur

X5.5.1 The limit on sulfur content is included to protect against engine wear, deterioration of engine oil, corrosion of exhaust system parts and degradation of emission control systems.

X5.6 Benzene

X5.6.1 Benzene is an air pollutant commonly found in spark-ignition engine fuels. Efforts are made to control the benzene content in the fuels to reduce the benzene emissions. Fuel ethanol does not contain benzene. The hydrocarbons are the source of benzene in denatured fuel ethanol (for example, Specification D4806) and ethanol fuel blends (for example, Specification D5798).

X6. MICROBIAL CONTAMINATION

X6.1 Uncontrolled microbial contamination in fuel systems can cause or contribute to a variety of problems including increased corrosivity, and decreased stability, filterability, and caloric value. Microbial processes in fuel systems can also cause or contribute to system damage.

X6.2 Because the microbes contributing to the aforementioned problems may not be present in the fuel itself, no microbial quality criterion for fuels is recommended. However, it is important that personnel responsible for fuel quality understand how uncontrolled microbial contamination can affect fuel quality.

X6.3 Guide D6469 provides personnel with limited microbiological background an understanding of the symptoms, occurrences, and consequences of chronic microbial contamination. Guide D6469 also suggests means for detecting and controlling microbial contamination in fuels and fuel systems.

X7. DESCRIPTION OF PRODUCTION AND GLOSSARY OF TERMS

X7.1 Production of Natural Gasoline

X7.1.1 Natural gas at the well is primarily methane and may come to the surface relatively 'lean' (dry), or 'rich' (wet) with quantities of ethane, propane, butanes, and heavier hydrocarbons, primarily C_5 to C_8+ (natural gasoline). Natural gas at the well may also contain impurities such as water, brine, carbon dioxide, hydrogen sulfide, helium, and other gases. Terms commonly used in the field for various products are listed below. Note that different geographical areas can use different names.

X7.1.2 Natural gas pipelines limit the amount of material heavier than methane and impurities in natural gas. This often requires that natural gas be processed to remove impurities to acceptable levels and remove hydrocarbons heavier than methane, including natural gasoline, to meet a maximum natural gas energy content or gross heating value and dew point.

X7.1.3 Some crude oil and condensate production contain volatile hydrocarbons, methane to pentanes. These light hydrocarbons, including natural gasoline components, can be removed to reduce the crude oil or condensate volatility to allow storage in non-pressurized tanks, ships, barges, tank cars and trucks. See Fig. X7.1.

X7.2 Common Terms Related in Natural Gasoline

X7.2.1 *Glossary of Terms*—Condensate and natural gasoline-related terms are placed first, then related terms in alphabetical order.

X7.2.1.1 *GPA*—stands for the Gas Processors Association, an organization that represents natural gas producers, gas plants, and mid-stream (LPG) facilities. Use of many of their definitions found in GPA Publication 1167-83, GPA Glossary—Definitions of Words and Terms Used in the Gas Processing Industry, is gratefully acknowledged.

X7.2.2 *condensate*—[based on a GPA definition] the hydrocarbon liquid separated from natural gas because of changes in temperature and pressure when the gas from the reservoir was delivered to the separators. Such condensate remains liquid at atmospheric temperature and pressure.

NOTE X7.1—In a totally different application, 'condensate' is the water condensed and returned to boilers in a steam system.

X7.2.3 *NGL (natural gas liquids)*—[GPA] natural gas liquids are those hydrocarbons liquefied at the surface in field facilities or in gas processing plants. Natural gas liquids include propane, butanes, and natural gasoline.

X7.2.4 *natural gasoline*—[GPA] a mixture of hydrocarbons, mostly pentanes and heavier, extracted from natural gas, which meets vapor pressure, end point, and other specifications for natural gasoline as adopted by the GPA. See also 'stabilized condensate.'

NOTE X7.2—Although not a part of the GPA definition, the 'heavy end' of natural gasoline varies by source—some may only go up to C_8 while traces of up to C_{12}+ can be found in others.

X7.2.5 *natural gasoline plant*—[GPA] one of the terms, now obsolete, used to denote a natural gas processing plant. Refer to definition of "gas processing" and "gas processing plant."

X7.2.6 *natural gas processing plant*—[GPA] modern term for gas processing plant, natural gasoline plant, gasoline plant, etc.

X7.2.7 *Casinghead gasoline*—a largely obsolete term for natural gasoline, but referenced within the DOT Hazardous Materials Table.

X7.2.8 *'dry' gas*—natural gas with little or no hydrocarbons heavier than C_4.

X7.2.9 The GPA Glossary has two definitions for 'Dry Gas':

X7.2.9.1 Gas whose water content has been reduced by a dehydration process.

X7.2.9.2 Gas containing little or no hydrocarbons commercially recoverable as liquid product. Gas in this second definition preferably should be called lean gas.

X7.2.10 *gas plant:*

X7.2.10.1 Generally 'raw' natural gas from several producing wells is piped to a field 'gas plant' which 'cleans up' the natural gas to meet pipeline quality requirements, removing water, salts, sulfur compounds, and sometimes ethane and C_3+ hydrocarbons, if present. Frequently, ethane is extracted from natural gas in large fields and sent to a petrochemical plant to make plastics and chemicals. H_2S (hydrogen sulfide) is converted to sulfur which can be stored as solid sulfur, sold as hot

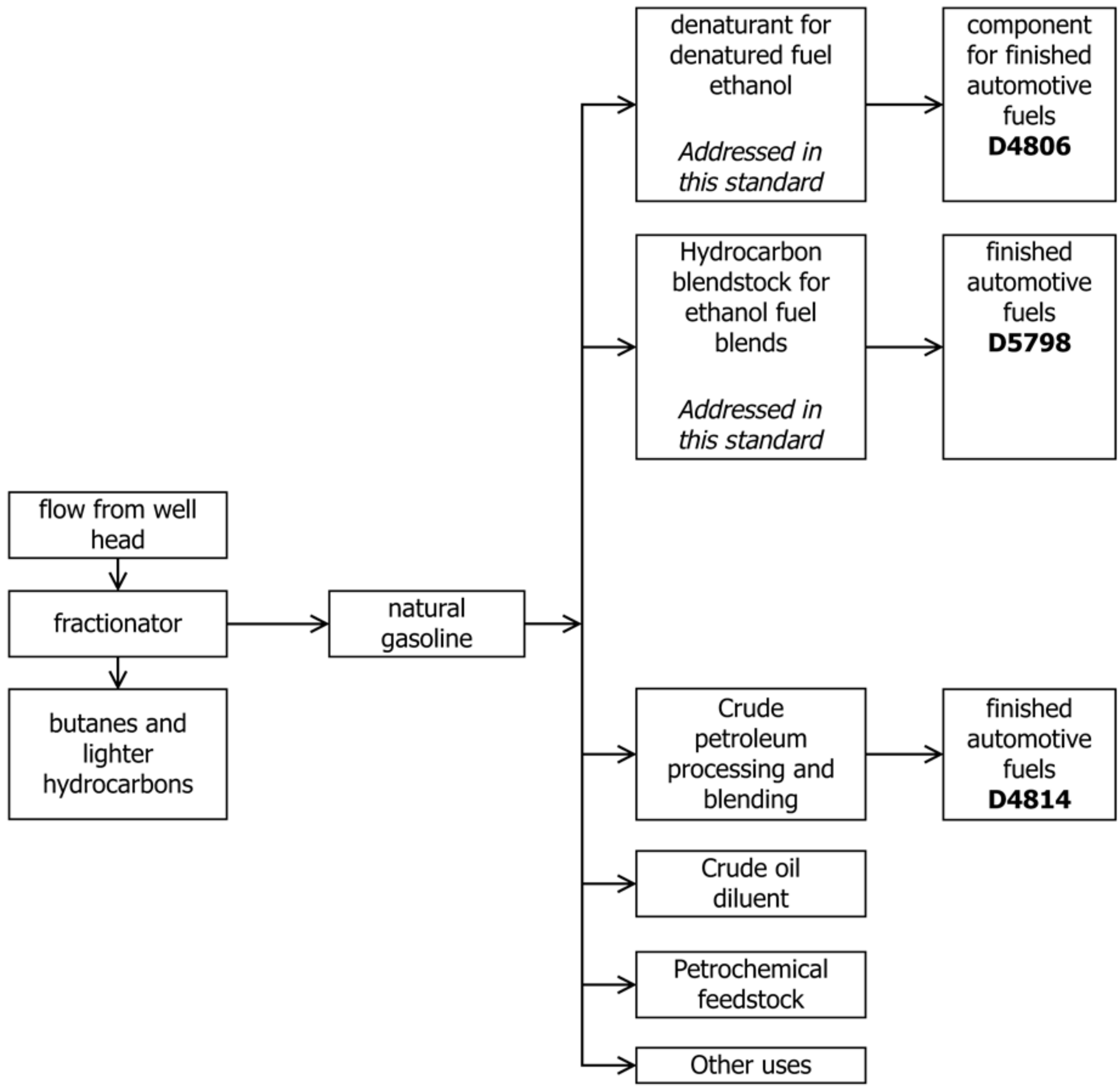

FIG. X7.1 Flow Chart for Production and Uses of Natural Gasoline from Well Head Sources

molten sulfur, sold as solid 'chunks' of sulfur, or prilled and sold as solid sulfur pellets.

X7.2.10.2 When hydrocarbon liquids are separated from natural gas, the 'raw' mixture of liquids is called condensate, which can have a significant vapor pressure.

X7.2.11 *heavy ends:*

X7.2.11.1 *In natural gas,* the portion of a hydrocarbon mixture having the highest boiling point. Usually hexanes or heptanes and all heavier hydrocarbons are the heavy ends in a natural gas stream. [hexane = C_6; heptane = C_7]

X7.2.11.2 *In refinery operations,* usually refers the high boiling portion of a fraction, such as the highest boiling portion of naphtha for gasoline, the highest boiling portion of middle distillate for diesel fuel, the highest boiling portion of vacuum gas oil, or the non-distilling portion (resid or residue) of crude oil.

X7.2.12 *lean gas [GPA]:*

X7.2.12.1 The residue gas [mostly methane] remaining after recovery of natural gas liquids in a gas processing plant.

X7.2.12.2 Unprocessed gas containing little or no recoverable natural gas liquids.

X7.2.13 *rich gas*—[GPA] a gas which is suitable as feed to a gas processing plant and from which [liquid] products can be extracted.

X7.2.14 *'sour' gas*—natural gas that contains H_2S (hydrogen sulfide) and/or mercaptans. [GPA: Gas containing an appreciable quantity of hydrogen sulfide and/or mercaptans.]

X7.2.15 *stabilized condensate*—condensate that has most propane and butanes removed to reduce the vapor pressure.

X7.2.15.1 The GPA definition of *stabilized condensate* states: Condensate that has been stabilized to a definite vapor pressure in a fractionation system.

X7.2.16 *stabilizer*—[GPA] a name for a fractionation system that ... reduces the vapor pressure so that the resulting liquid is less volatile. [While not part of the GPA definition a stabilizer, also called a 'stripper,' could be used for high volatility crude oil to reduce the vapor pressure for transportation of the crude.]

X7.2.17 *straddle plant*—a gas processing plant situated on a large natural gas pipeline which removes most of the ethane, propane, butanes, and heavier hydrocarbons to produce either 'natural gas liquids' [NGL] or separate components: ethane, propane, butanes, and 'pentanes plus' (C_5+ hydrocarbons).

X7.2.18 *straight run*—a term used in a petroleum refinery to describe a stream or intermediate product from the atmospheric distillation tower, the first process in refining crude oil after it is received at a refinery and cleaned up to remove dirt, salt, and water. Thus 'straight run naphtha' is the portion of the crude oil generally from pentanes (C_5) to about C_8 to C_{12} (depending on individual refinery operations) from the distillation of crude oil. The term implies that no further processing has taken place, such as hydrotreating, reformation, isomerization, or alkylation.

X7.2.19 *'sweet' gas*—natural gas that contains no significant amount of H_2S (hydrogen sulfide). [GPA: Gas which has no more than the maximum sulfur content defined by (*1*) the specifications for the sales gas from a plant; (*2*) the definition by a legal body such as the Railroad Commission of Texas]

X7.2.20 *'wet' gas*—[GPA] (*1*) a gas containing water, or a gas which has not been dehydrated. (*2*) a term synonymous with rich gas, that is, a gas from which [liquid] products have not been extracted. Refer to definition of 'rich gas.'

SUMMARY OF CHANGES

Subcommittee D02.A0 has identified the location of selected changes to this standard since the last issue (D8011 – 16) that may impact the use of this standard. (Approved Jan. 1, 2017.)

(1) Added new subsection 3.3.
(2) Added new footnotes to Table 1, Table X1.1, Table X1.2; revised Table X4.1.
(3) Revised subsection X3.1.2, adding new subsections X3.1.2.1 and X3.1.2.2.
(4) Deleted former subsection X3.5.2.1.
(5) Added new subsections X3.2.2 and X4.2.3.1.