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Overview of a Comprehensive Resource Database for the Assessment of Recoverable Hydrocarbons Produced by Carbon Dioxide Enhanced Oil Recovery

Chapter 16 of
Section C, Computer Programs
Book 7, Automated Data Processing and Computations

Techniques and Methods 7–C16
Version 1.1, June 2018

U.S. Department of the Interior
U.S. Geological Survey

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By Marshall Carolus, Khosrow Biglarbigi, Peter D. Warwick, Emil D. Attanasi, Philip A. Freeman, and Celeste D. Lohr

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Conversion Factors

Multiply	By	To obtain
	Length	
foot (ft)	0.3048	meter (m)
kilometer (km)	0.6214	mile (mi)
	Area	
square inch (in^2)	6.452	square centimeter (cm^2)
acre	43,560	square foot (ft^2)
	Volume	
barrel (bbl) of petroleum	42	gallon (gal)
barrel (bbl) of petroleum	0.1590	cubic meter (m^3)
thousand barrels (Mbbl) of petroleum	1,000	barrel (bbl) of petroleum
million barrels (MMbbl) of petroleum	1,000,000	barrel (bbl) of petroleum
cubic foot (ft^3)	0.02832	cubic meter (m^3)
thousand cubic feet (Mcf)	28.32	cubic meter (m^3)
million cubic feet (MMcf)	2,832	cubic meter (m^3)
billion cubic feet (Bcf)	28,316,847	cubic meter (m^3)
	Mass	
pound, avoirdupois (lb)	0.4536	kilogram (kg)
	Pressure	
pound-force per square inch (lbf/in^2 or psi) measured in ambient atmospheric pressure	6.895	kilopascal (kPa)
pound-force per square inch (lbf/in^2 or psia) absolute measured in a vacuum	6.895	kilopascal (kPa)
	Pressure gradient	
pound-force per square inch per foot ($lbf/in^2/ft$ or psi/ft)	22.62	kilopascal per meter (kPa/m)
	Geothermal gradient	
degrees Fahrenheit per foot (°F/ft)	1.82	degrees Celsius per meter (°C/m)
	Permeability	
millidarcy (mD)	9.869×10^{-16}	square meter (m^2)
	Viscosity	
centipoise (cP)	1	millipascal second (mPa · s)
	Energy	
British thermal unit (Btu)	1	1,055.05585262 joules (J)

Temperature in degrees Celsius (°C) may be converted to degrees Fahrenheit (°F) as follows:

$$°F=(1.8\times°C)+32$$

Temperature in degrees Fahrenheit (°F) may be converted to degrees Celsius (°C) as follows:

$$°C=(°F-32)/1.8$$

Temperature in degrees Fahrenheit (°F) may be converted to degrees Rankine (oR) as follows:

$$°R=°F+460$$

1 barrel of oil equivalent (BOE) = 1 barrel of crude oil (42 gallons)
= 6,000 cubic feet of natural gas
= 1.5 barrels of natural gas liquids

Abbreviations

a	reservoir production proration factor one, two, or three
A	coefficient value determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975)
ACPROD	producing area, in acres
API	American Petroleum Institute gravity of oil, in degrees API (°API)
Area	reservoir area, in acres
AreaOOIP	calculated recoverable original oil in place, in stock tank barrels (STB) or thousands of stock tank barrels (MSTB)
B	is an exponent determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975)
bbl	barrel
Bcf	billions of cubic feet
B_{CO2}	CO_2 formation volume factor, in decimal format
BGC	current gas formation volume factor, in decimal format
BGI	initial gas formation volume factor, in decimal format
BOC	current oil formation volume factor, in decimal format
BOE	barrel of oil equivalent
BOI	initial oil formation volume factor, in decimal format
Btu	British thermal unit
CO_2	carbon dioxide
cP	centipoise
CRD	Comprehensive Resource Database
crespro	NRG cumulative production of the reservoir (2008–2010), in thousands of barrels (Mbbl) or billions of cubic feet (Bcf)
cumprod	cumulative oil production, in thousands of barrels (Mbbl); or the cumulative gas production, in billions of cubic feet (Bcf)
Dary(i,16)	depth of play, in feet (ft) in year (*i*), 16th numerical position in Fortran computer code
Dary(i,17)	temperature of play, in degrees Fahrenheit (°F) in year (*i*), 17th numerical position in Fortran computer code
dist	fraction of proration factor "a" for the reservoir
dist_(a,res)	reservoir distribution factor
EIA	U.S. Energy Information Administration
EIA ID	U.S. Energy Information Administration identification
EOR	enhanced oil recovery
ER	recovery factor after waterflood, in decimal format

EUR	estimated ultimate recovery, in standard cubic feet (Scf) or millions of cubic feet (MMcf)
EV_1	pseudo-volumetric sweep efficiency, in decimal format
EV_2	pseudo-volumetric sweep efficiency, in decimal format
exp	exponent to the base e (the base of natural logarithms approximately equal to 2.71828)
F	coefficient for the initial oil formation volume factor equation
fact_one(res)	is proration factor one
fact_two(res)	is proration factor two
fact_three(res)	is proration factor three
fdata(ifld,iyr)	annual field production of oil, gas, or natural gas liquids (NGL) in year analyzed (*iyr*)
fldwell(ifld,iyr)	annual number of wells in the field in year analyzed (*iyr*)
FMaster	Nehring Associates (2012) (NRG) field reservoir data
ft	feet
GIPVOL	original gas-in-place volume per unit area, in standard cubic feet per acre (Scf/acre)
GOR	gas-oil ratio
H_2S	hydrogen sulfide
i	year
ifld	field that is matched to the reservoir
IHS	IHS Inc. (2012)
Ihsprod	IHS Inc. (2012) (IHS) annual oil or gas production from the field, in thousands of barrels (Mbbl) or millions of cubic feet (MMcf)
iyr	year analyzed
k	play being analyzed
KR_{gas}	Nehring Associates (2012) (NRG) known gas recovery (cumulative production plus reported reserves), in millions of cubic feet (MMcf)
KR_{NGL}	Nehring Associates (2012) (NRG) known natural gas liquids (NGL) recovery (cumulative production plus reported reserves), in thousands of barrels (Mbbl)
KR_{oil}	Nehring Associates (2012) (NRG) known oil recovery (cumulative production plus reported reserves), in thousands of barrels (Mbbl)
Mbbl	thousands of barrels
Mcf	thousands of cubic feet
mD	millidarcy
MMbbl	millions of barrels
MMcf	millions of cubic feet
MMP	minimum miscibility pressure

MSTB	thousands of stock tank barrels
N_2	nitrogen
NETL	National Energy Technology Laboratory
NetPay	net reservoir thickness, in feet (ft)
NGL	natural gas liquids
NOGA	USGS National Oil and Gas Assessment
NPC	National Petroleum Council
nres	number of reservoirs in the field
NRG	Nehring Associates (2012) database
NRG ID	Nehring Associates (2012) database identification number
num_thick	number of non-zero values in the play or province
OGIP	original gas in place, in standard cubic feet (Scf) or billions of cubic feet (Bcf)
OOIP	original oil in place, in stock tank barrels (STB) or thousands of stock tank barrels (MSTB)
OrgArea(i)	calculated reservoir area, in acres in year (*i*)
playthick	non-zero average thickness of the reservoir in the play or province, in feet (ft)
Ply_PresGr	average pressure gradient of play, in pound-force per square inch per foot (psi/ft)
Ply_TempGr	average temperature gradient of play, in degrees Fahrenheit per foot (°F/ft)
Por	reservoir rock porosity, in decimal format
PRESC	current reservoir pressure, in pound-force per square inch absolute (psia)
PresCal	calculated initial reservoir pressure, in pound-force per square inch absolute (psia)
PRESIN	initial reservoir pressure, in pound-force per square inch absolute (psia)
psi	pound-force per square inch
psia	pound-force per square inch absolute
RECY	gas reservoir recovery factor, in decimal format
res	reservoir analyzed
respro	annual reservoir oil, gas, or natural gas liquid (NGL) production, in thousands of barrels (Mbbl) or millions of cubic feet (MMcf)
respro(res,iyr)	annual reservoir production of oil, gas, or natural gas liquids (NGL) in year analyzed (*iyr*)
resprod(res,iyr)	annual production of oil, gas, or natural gas liquid (NGL) converted to barrels of oil equivalent (BOE) in year analyzed (*iyr*)
reswell(res,iyr)	annual number of wells in the reservoir in year analyzed (*iyr*)
RMaster	Nehring Associates (2012) (NRG) reservoir properties and production data

RS	solution gas-oil ratio, in standard cubic feet per stock tank barrel (Scf/STB)
Scf	standard cubic foot at standard conditions (14.73 pound-force per square inch [psi] and 60 degrees Fahrenheit [°F])
Scf/acre	standard cubic feet per acre
SGC	current gas saturation, in decimal format
SGG	specific gravity of the gas, air=1
SGI	initial gas saturation, in decimal format
SGO	specific gravity of oil
SOC	current oil saturation, in decimal format
SOI	initial oil saturation, in decimal format
SORW	residual oil saturation after waterflood, in decimal format
STB	stock tank barrel (volume of treated oil stored in stock tanks at surface conditions; the size of a stock tank barrel is the same as the size of a regular barrel [bbl])
SWC	current water saturation, in decimal format
SWI	initial water saturation, in decimal format
thick	non-zero thickness of the reservoir in the play or province
Tres	reservoir temperature, in degrees Fahrenheit (°F)
$Tres_c$	current reservoir temperature, in degrees Fahrenheit (°F)
$Tres_i$	initial reservoir temperature, in degrees Fahrenheit (°F)
U.S.	United States
USGS	U.S. Geological Survey
VCO_2	carbon dioxide viscosity, in centipoise (cP)
VDP	pseudo-Dykstra-Parsons coefficient
VWAT	water viscosity, in centipoise (cP)
WATIN	reservoir water influx (volume)
WLSPC	well spacing
WOR	water-oil ratio
X	coefficient for the Beggs and Robinson (1975) correlation equation
Yg	coefficient for the solution gas-oil ratio equation
Z_c	current gas compressibility factor, dimensionless
Z_{CO2}	CO_2 compressibility factor, CO_2 dimensionless Z-factor
Z factor	compressibility of gas
Z_i	initial gas compressibility factor
μ	oil viscosity, in centipoise (cP)
μ_DEAD	dead oil viscosity (no dissolved gas), in centipoise (cP)
μ_LIVE	live oil viscosity (with dissolved gas), in centipoise (cP)

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By Marshall Carolus,[1] Khosrow Biglarbigi,[1] Peter D. Warwick,[2] Emil D. Attanasi,[2] Philip A. Freeman,[2] and Celeste D. Lohr[2]

Abstract

A database called the “Comprehensive Resource Database” (CRD) was prepared to support U.S. Geological Survey (USGS) assessments of technically recoverable hydrocarbons that might result from the injection of miscible or immiscible carbon dioxide (CO_2) for enhanced oil recovery (EOR). The CRD was designed by INTEK Inc., a consulting company under contract to the USGS. The CRD contains data on the location, key petrophysical properties, production, and well counts (number of wells) for the major oil and gas reservoirs in onshore areas and State waters of the conterminous United States and Alaska. The CRD includes proprietary data on petrophysical properties of fields and reservoirs from the “Significant Oil and Gas Fields of the United States Database,” prepared by Nehring Associates in 2012, and proprietary production and drilling data from the “Petroleum Information Data Model Relational U.S. Well Data,” prepared by IHS Inc. in 2012. This report describes the CRD and the computer algorithms used to (1) estimate missing reservoir property values in the Nehring Associates (2012) database, and to (2) generate values of additional properties used to characterize reservoirs suitable for miscible or immiscible CO_2 flooding for EOR. Because of the proprietary nature of the data and contractual obligations, the CRD and actual data from Nehring Associates (2012) and IHS Inc. (2012) cannot be presented in this report.

Introduction

The Comprehensive Resource Database (CRD) was developed to support U.S. Geological Survey (USGS) assessments of technically recoverable hydrocarbons that could be potentially recovered from qualifying reservoirs through enhanced oil recovery (EOR) using carbon dioxide (CO_2). The CRD was designed by INTEK Inc., a petroleum engineering consulting company under contract to the USGS (contract G13PC00006). The CRD contains data relating to the location, key petrophysical properties, production, and the “well count” (number of wells) for the major oil and gas reservoirs in the onshore and State waters areas of the conterminous United States and Alaska. The data within the CRD are proprietary because they include (1) field and reservoir properties data from the proprietary sources “Significant Oil and Gas Fields of the United States Database” (also referred to as “NRG” or “NRG database” in this report) prepared by Nehring Associates in 2012, and (2) proprietary production and drilling data from “Petroleum Information Data Model Relational U.S. Well Data” (also referred to as “IHS” in this report) prepared by IHS Inc. in 2012.

The following sections provide a description of (1) the CRD computer program and its methodology, (2) a list of the key data sources used in its development, (3) a description of the steps and routines used to prepare the CRD, (4) the screening criteria for miscible or immiscible CO_2 flooding applied to the CRD, and (5) the database outputs. The resulting CRD contains a deterministic representation of reservoir properties that will be used in a probabilistic methodology that the USGS is developing to estimate technically recoverable oil resulting from the application of the CO_2-EOR process. A description of the equations used in the calculations, a list of the input and output reservoir property data, the computer code, and the CRD are on file at the USGS Eastern Energy Resources Science Center located in Reston, Virginia.

Program Structure

Program Language and Compilation

The computer code that generated the CRD was developed using Lahey Fortran 90® (software owned by INTEK) and the Lahey/Fujitsu Fortran Professional v7.3® (owned by USGS). The model was coded using Fortran 77 standards and compiled using the LF95 Lahey/Fujitsu optimized compiler.

[1]INTEK Inc., under contract to the U.S. Geological Survey.

[2]U.S. Geological Survey.

Structure

The computer code that generated the CRD contains files and executables in three main directories. The directories are Input, Code, and Output. The data files used to prepare the CRD are contained in the Input directory. The executable and source code for the program are contained in the Code directory. The processed data files, created by the CRD computer code, are contained in the Output directory. Descriptions of the input and output files are provided in the respective sections of this report. The three directories are not part of this report, and will not be available to the public because of their proprietary nature.

Model Methodology

Model Objective

The computer code that generated the CRD uses a series of Fortran 90® routines, based upon petroleum engineering principles, to ensure the completeness and internal consistency of the Nehring Associates (2012) data contained within the resource database. As discussed in this report, the routines check the values contained in the Nehring Associates (2012) database, modify those which are inconsistent with production or other reservoir properties, and estimate the missing values with average values calculated from reservoirs of the same play or province. The reservoirs were organized by the geologic plays and provinces identified in the USGS 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996). In addition, the routines determine the classification of the reservoir (as oil or gas) and incorporate reservoir production and drilling data from IHS Inc. (2012). This methodology has previously been applied to the "Comprehensive Oil and Gas Analysis Model" prepared by the U.S. Department of Energy National Energy Technology Laboratory (2004), and to the "Onshore Lower 48 Oil and Gas Supply Submodule" (INTEK Inc. and Resource Consultants Inc., 2006) within the National Energy Modeling System at the U.S. Energy Information Administration.

Logic of Data Processing Structure

The computer code that generated the CRD has a modular structure with seven major components (fig. 1). The steps described below utilize the various data elements listed in tables 1 through 5. These seven principal components of the processing logic include:

1. **Read NRG data and supplemental data:** opens and reads the input files used in the module.

2. **Calculate average properties for oil and gas reservoirs:** uses the Nehring Associates (2012) data along with supplemental data (described below) to calculate the average values for key petrophysical properties for each play, province, and region. The key properties are listed in table 1.

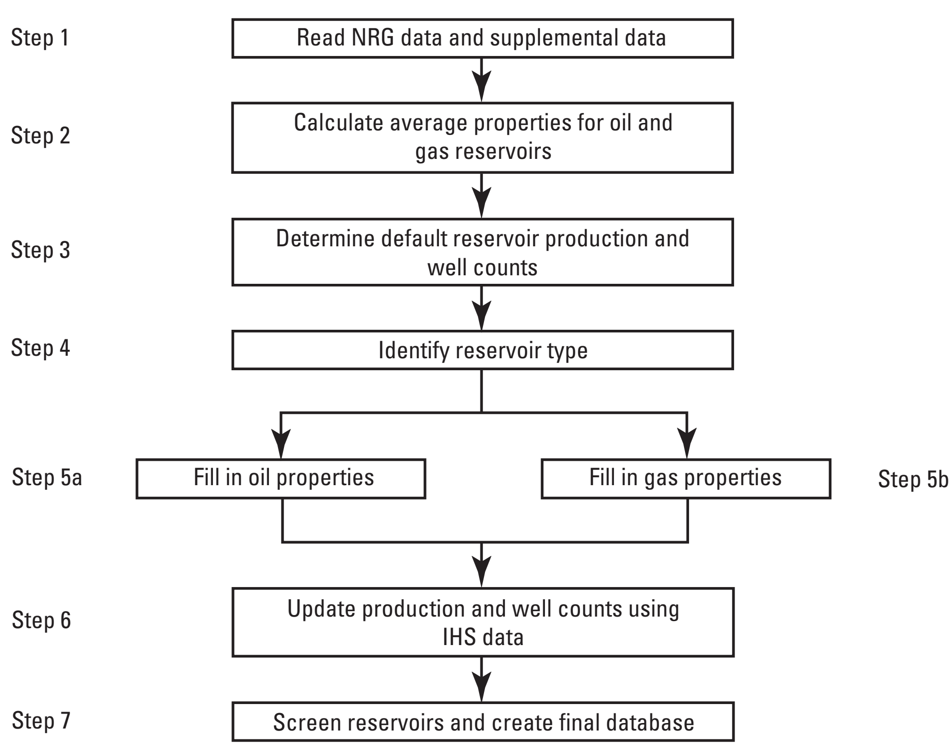


Figure 1. Flowchart showing the logic steps of the data processing algorithm that builds the Comprehensive Resource Database (CRD). Abbreviations: NRG, Nehring Associates (2012) database; IHS, IHS Inc. (2012).

Table 1. Key petrophysical properties from the Nehring Associates (2012) database used in the Comprehensive Resource Database (CRD).

[The computer code that generated the CRD calculates the arithmetic average values at the play, province, region, or Nation levels, as well as the maximum and minimum values for the properties. Abbreviations: API, American Petroleum Institute; CO_2, carbon dioxide; H_2S, hydrogen sulfide; N_2, nitrogen]

Oil and gas reservoirs	Oil reservoirs	Gas reservoirs
Net pay (thickness)	Initial oil saturation	Initial gas saturation
Depth	Initial water saturation	Initial water saturation
Temperature gradient	Initial formation volume factor	CO_2 concentration
Pressure gradient	API gravity of oil	N_2 concentration
Porosity	Specific gravity of the gas	H_2S concentration
Permeability	Well spacing	Specific gravity of the gas
	Sulfur content	Heat content
		Sulfur content

3. **Determine default reservoir production and well counts:** the Nehring Associates (2012) database is used for annual oil, gas, and natural gas liquids (NGL) production data and well counts for each reservoir.

4. **Identify reservoir type:** for purposes of classifying reservoirs as oil or gas and noting that only oil reservoirs will be candidates for CO_2 enhanced oil recovery (EOR), an oil reservoir was defined as having less than 10,000 standard cubic feet (Scf) of natural gas per stock tank barrel (STB) of oil. This classification conforms to the demonstrated CO_2-EOR projects listed in Kootungal (2012, 2014) and is used by some regulatory agencies to determine the primary product of hydrocarbon reservoirs (British Columbia Oil and Gas Commission, 2014). This value is lower than the 20,000 standard cubic feet per barrel (Scf/bbl) limit used in USGS assessments of undiscovered oil and gas resources (Klett and others, 2005).

5. **Fill in oil and gas properties:** computes the oil and gas properties in the database (shown as steps 5a and 5b in fig. 1). In addition, an accompanying “shadow” database is created that specifies the data source for each estimated property. Table 2 displays the calculated oil and gas properties.

6. **Update production and well counts using IHS data:** updates the reservoir production, and well counts using IHS Inc. (2012) data.

7. **Screen reservoirs and create final database:** creates the final reservoir database by applying screening criteria (described below) to determine the candidates for miscible and immiscible CO_2-EOR.

Data Sources

The database is assembled from the following three data types and sources: (1) reservoir and field production data and properties from the Nehring Associates (2012) database, (2) field-level production and well-count data from IHS Inc. (2012), and (3) supplemental data from several different sources (fig. 2). The routines and equations discussed below are used to ensure that the data from these sources are complete and internally consistent. This section describes the data sources.

Nehring Associates (2012) provides reservoir (RMaster) and field (FMaster) production data, well counts, and key petrophysical properties for the major oil and gas fields and reservoirs in the United States. Production and well-count data are current through 2010 in the database from Nehring Associates (2012). These two Nehring Associates (2012) files (RMaster, FMaster) are used in the assembly of the reservoir data in the CRD. All data in the CRD from Nehring Associates (2012) are provided in English units unless otherwise noted.

Nehring Associates (2012) RMaster File

The Nehring Associates (2012) RMaster file contains data for approximately 26,000 oil and gas reservoirs in the United States. There are three basic types of reservoir data in the NRG RMaster file, including: (1) reservoir identification information, (2) reservoir characteristics and properties, and (3) reservoir production and reserves through 2010. The computer code that generates the CRD uses the input values from the NRG RMaster file for these 3 types of reservoir data shown in table 3.

Table 2. Calculated oil and gas reservoir properties in the Comprehensive Resource Database (CRD).

[The averaged property values in the CRD are indicated by footnote 1. Abbreviations: API, American Petroleum Institute; CO_2, carbon dioxide; H_2S, hydrogen sulfide; N_2, nitrogen; NGL, natural gas liquids; Z factor, compressibility of gas]

Oil properties	Gas properties
[1]Net pay (thickness)	[1]Net pay (thickness)
[1]Depth	[1]Depth
[1]Temperature gradient	[1]Temperature gradient
[1]Pressure gradient	[1]Pressure gradient
[1]Porosity	[1]Porosity
[1]Permeability	[1]Permeability
[1]Initial oil saturation	[1]Initial gas saturation
[1]Initial water saturation	[1]Initial water saturation
[1]Initial formation volume factor	[1]CO_2 concentration
[1]API gravity of oil	[1]N_2 concentration
[1]Specific gravity of the gas	[1]H_2S concentration
[1]Well spacing	[1]Specific gravity of the gas
Reservoir area	[1]Heat content
Active wells	[1]Sulfur content
[2]Original oil in place	Initial gas formation volume factor
Recovery factor	Lithology type
Current pressure	Well spacing
Current formation volume factor	Producing area
Current oil saturation	Gas compressibility
Current water saturation	Gas-in-place volume
Current gas saturation	Recovery factor
Gas-to-oil ratio	Original gas in place
Swept zone oil saturation	Current gas formation volume factor
Viscosity	Current temperature
Pseudo Dykstra-Parsons coefficient	Current oil saturation
Size class	Current water saturation
Lithology	Current gas saturation
	Current Z factor
	Water influx
	NGL-to-gas ratio
	Condensate-to-gas ratio
	Viscosity
	Size class

[1]Averaged property values in the CRD.

[2]Adjusted if recovery factor is greater than 35 percent. Adjusted volumetrics are checked against the play range and unpublished U.S. Geological Survey data.

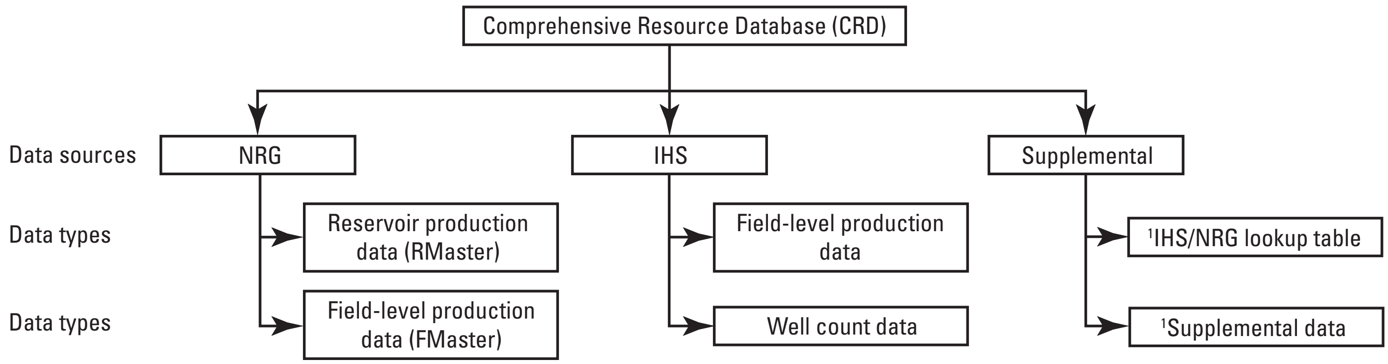


Figure 2. Flowchart showing the three data types and sources used in compiling the Comprehensive Resource Database (CRD). [1]Described in report under Supplemental data. Abbreviations: IHS, IHS Inc. (2012); NRG, Nehring Associates (2012) database.

Table 3. Nehring Associates (2012) oil and gas reservoir identification, reservoir characteristics and properties, and production and reserves data through 2010 (all in the Nehring Associates (2012) RMaster file).

[Abbreviations: API, American Petroleum Institute; BOE, barrels of oil equivalent; Btu, British thermal units; EIA ID, U.S. Energy Information Administration identification number; NGL, natural gas liquids; NRG, Nehring Associates (2012) database; NRG ID, Nehring Associates (2012) database identification number; U.S., United States]

Reservoir identification	Reservoir characteristics and properties	Reservoir production and reserves data through 2010
NRG ID	Depth to top	Oil, gas, and NGL
Field and reservoir names	Well spacing	- Annual production (1991–2010)
State name	Thickness	- Known recovery (1991–2010)
County name	Permeability	- Cumulative production
Province name	Oil viscosity	- Proved reserves
NRG play number	Initial oil saturation	
U.S. play number	Initial gas saturation	BOE
EIA ID	Initial water saturation	- Known recovery (1991–2010)
State code	Pressure	- Cumulative production
County code	Lithology	- Proved reserves
Province code	Gas impurities	
	Oil formation volume factor	
	Reservoir area	
	Number of spacing units	
	Porosity	
	API gravity of oil	
	Specific gravity of the gas	
	Temperature	
	Gas Btu	
	Recovery factor	
	Age rank	

Nehring Associates (2012) FMaster File

The Nehring Associates (2012) FMaster file contains data on approximately 17,000 oil and gas fields in the United States. There are four categories of field data in the NRG FMaster file, including: (1) field identification, (2) field properties, (3) production data through 2010, and (4) well counts (number of wells). The computer code that generates the CRD uses the input values from the NRG FMaster file for these 4 categories of field data shown in table 4.

IHS Inc. (2012) Data

The IHS Inc. (2012) (“IHS”) data contains well identification, production, and field information. All data from IHS are provided in English units unless otherwise noted. The USGS summed the IHS data to the field level and matched them with the corresponding NRG database fields. The summation process involved creating a file based on IHS data that contains the well counts, well type, and production data matched to the fields in the NRG database. The resulting

Table 4. Nehring Associates (2012) field identification, field properties, production data, and well counts (all in the Nehring Associates (2012) FMaster file).

[Abbreviations: BOE, barrels of oil equivalent; EIA, U.S. Energy Information Administration; NGL, natural gas liquids; NRG ID, Nehring Associates (2012) database identification number]

Field identification	Field properties	Production data through 2010	Well counts
NRG ID	Field area	Oil, gas, and NGL	Active wells
Field name	Original oil in place	- Annual production	Producing wells
State name	Current oil recovery factor	- Known recovery	
County name		- Cumulative production	
Province name		- Proved reserves	
EIA ID			
		BOE	
		- Known recovery	
		- Cumulative production	
		- Proved reserves	

Table 5. IHS Inc. (2012) field identification, production data, and well counts.

[Abbreviations: NRG ID, Nehring Associates (2012) database identification number]

Field identification	Production data	Well counts
NRG ID	Annual production (2000–2012)	Annual number of wells (2000–2012)
Field name	- Oil	- Producing oil wells
State abbreviation	- Condensate	- Producing gas wells
County number	- Gas	- Injection wells
County name	- Casinghead gas	- New oil wells
Formation number	- Water produced	- New gas wells
Formation name	- Water injected	- New injection wells
	Cumulative production	Cumulative number of wells
	- Oil	- Producing oil wells
	- Condensate	- Producing gas wells
	- Gas	- Injection wells
	- Casinghead gas	
	- Water produced	
	- Water injected	

IHS file contains the matched NRG identification number (NRG ID), annual production for 2000 to 2012, cumulative production, and annual and cumulative well counts (number of wells), as shown in table 5. The field production and well counts prior to the year 2000 were added as cumulative totals. The computer code uses the IHS data to extend the NRG production and well data to the most recent years (2010–2012).

The computer code that generates the CRD starts by matching the NRG cross reference to IHS data for each NRG ID. The program then finds the corresponding IHS data field and gathers all the well information by first assembling all the producing leases and wells (called "entities" in IHS) for the given IHS field. Once the program has all the entities, it loops through each entity by first counting all the oil, gas, and injection wells by summing the totals from year to year, then calculating the new well totals as positive values between years, and finally calculating the cumulative wells by adding all the new well totals together. After the well counts have been summed, the program calculates the production totals for oil, condensate, gas, casinghead gas, water produced, and water injected by looping through the monthly production table and summing all the monthly data to obtain yearly totals. The IHS fields "well counts" and "production data" are retrieved from the IHS data and then related to the associated NRG field in the cross reference. The program will also categorize these totals according to the U.S. State (determines State totals). Totals are converted from barrels (bbl) and thousands of cubic feet (Mcf) of gas to millions of barrels (MMbbl) and millions of cubic feet (MMcf) and then written to a formatted text file.

Supplemental Data

Some additional sources of information not contained in the Nehring Associates (2012) ("NRG") database and IHS Inc. (2012) ("IHS") data were required to help prepare the CRD. The following supplemental data were used in building the CRD:

- **IHS/NRG lookup table**—Provides a cross reference between fields in the IHS data and NRG database. The version available to USGS was developed by Nehring Associates (2008).
- **Active EOR projects**—Projects tracked by the "Oil and Gas Journal" that is published semiannually as a special survey report. The reports used in the CRD are by Koottungal (2012, 2014), which list most active projects that are using either CO_2, chemical, or thermal EOR processes. The EOR fields described by Koottungal (2012, 2014) were matched to a NRG ID. The CRD identifies these reservoirs as currently undergoing EOR.
- **Water-oil ratios by State**—Provided from the Argonne National Laboratory study by Clark and Veil (2009). The study reports hydrocarbon-specific water-oil ratios (WOR) for 15 States. For the remainder of States, the produced oil and water was used to calculate the WOR.
- **State level oil and gas production**—Provided by the U.S. Energy Information Administration (2013a, b). The petroleum online database provides annual data estimates on a continuing updated basis. These data are used to update reservoir totals in U.S. States where IHS does not provide current data.
- **Default lithologies**—Based on the dominant lithology of each USGS play reported in the USGS National assessment of the United States oil and gas resources by Gautier and others (1995) and are applied to the reservoirs for which the lithology in the NRG database is not provided.
- **Unpublished USGS data**—Reservoir type (conventional or continuous), temperature, pressure, and formation volume factor data are included in the CRD model. Reservoirs (accumulations) were designated as either conventional or continuous based on previous USGS assessment evaluations. Klett and others (2005) defines conventional reservoirs as having a discrete accumulation commonly bounded by a down-dip water contact and significantly affected by the buoyancy of petroleum in water; continuous accumulations are those that are pervasive throughout a large area, not significantly affected by hydrodynamic influences, and lack well-defined down-dip water contacts. The temperature, pressure, and formation volume factor data in the CRD were compiled at the province level from the National assessment of geologic CO_2 storage (U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013). Temperature and pressure data were provided by Marc Buursink (USGS, written commun., 2013) and formation volume factor data were provided by Hossein Jahediesfanjani (contractor with USGS, written commun., 2013). The data were used to limit the calculated formation volume factor and to fill in missing pressure and temperature values.
- **Gas contaminates data**—Supplemented from the USGS Energy Resources Program Geochemistry Database (2014). Reservoir contaminates included in the CRD module are carbon dioxide (CO_2) in 34 States, hydrogen sulfide (H_2S) in 18 States, and nitrogen (N_2) in 33 States. In addition to state level averages, a Nation average is calculated for each contaminant. These were used to fill in missing properties for the gas reservoirs contained in the NRG database.

Data Preparation

To prepare the CRD, (1) average reservoir properties are calculated, (2) the reservoirs are characterized as either oil or gas, (3) the petrophysical properties are calculated and validated for consistency and completeness (as discussed in sections below on oil and gas reservoir properties), (4) the production and well counts are updated, (5) the final resource characterization is completed, and (6) the reservoirs are screened to determine candidates for CO_2 flooding. This section provides details on the preparation of the data. In each step of the process, a "shadow" value is assigned that identifies the data source for each property (NRG database, IHS data, or supplemental data).

Geographic Regions

To ensure completeness of the CRD, the algorithm calculates average values for several volumetric properties. These averages are calculated at the following levels:

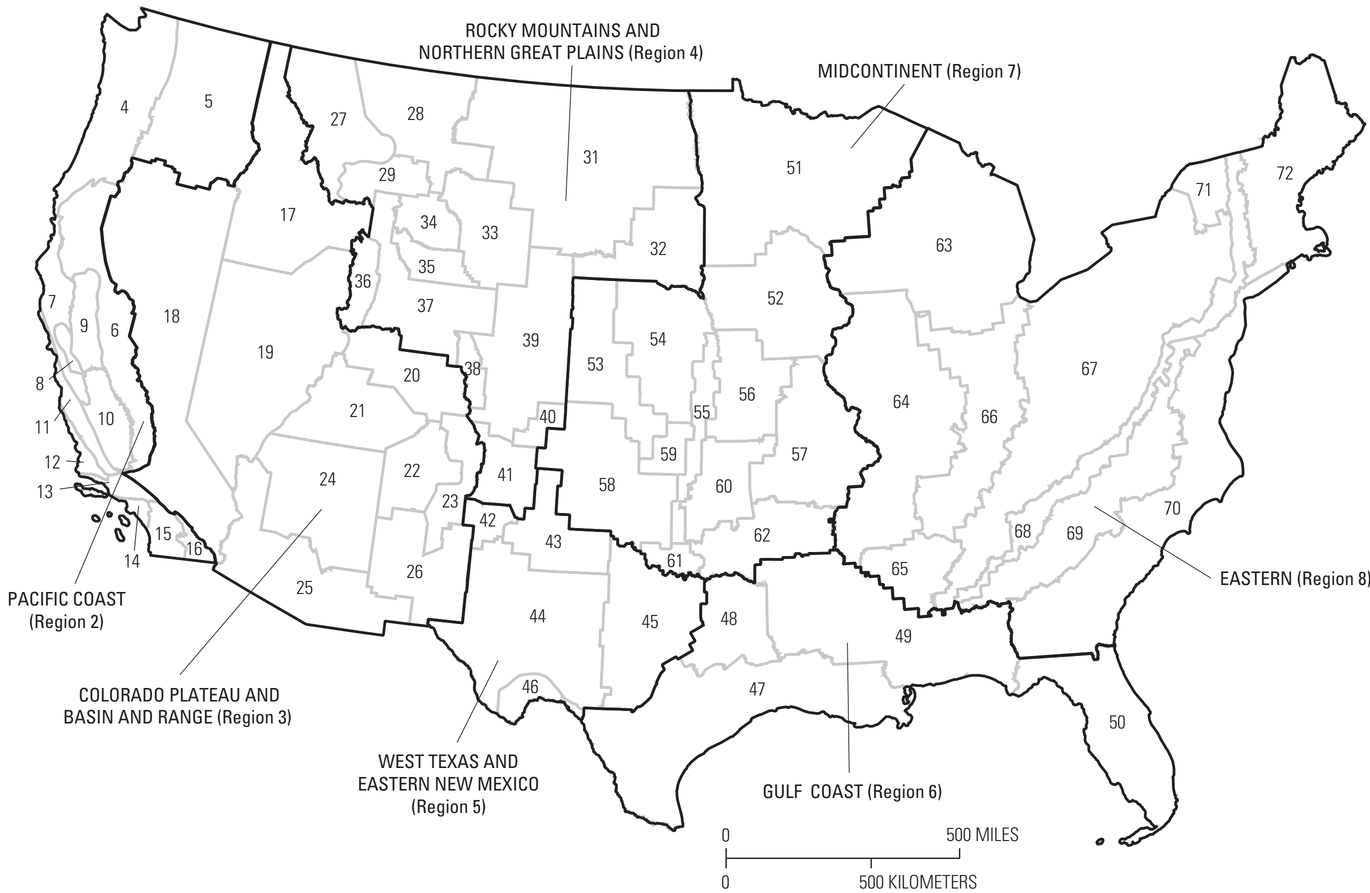
- Play
- Province
- Region
- Nation

The reservoirs in the CRD are classified by the plays, provinces, and regions based on definitions from the USGS 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996). Maps of the provinces and regions are provided in figure 3.

Calculating Averages

Table 7 provides a list of the properties which are calculated for three reservoir categories: (1) oil and gas reservoirs, (2) oil reservoirs, and (3) gas reservoirs. Averages are calculated for properties that apply to both oil and gas reservoirs and for properties that are specific to either oil reservoirs or gas reservoirs. The averages that apply to both oil and gas reservoirs are calculated before the averages for either oil reservoirs or gas reservoirs. The averages that are specific to either oil reservoirs or gas reservoirs are calculated after the initial reservoir type has been determined.

A



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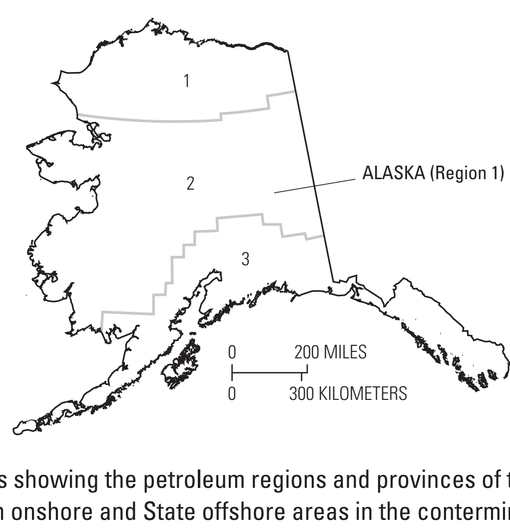

Figure 3. Maps showing the petroleum regions and provinces of the conterminous United States and Alaska. *A*, Petroleum regions and provinces in onshore and State offshore areas in the conterminous United States. Heavy lines are region boundaries; lighter lines are province boundaries. *B*, Petroleum provinces of the onshore and State offshore areas of Alaska. Regions and provinces shown in figures 3*A* and 3*B* are listed by name and number in table 6. From the U.S. Geological Survey's 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996; Attanasi, 1998).

Table 6. List of petroleum regions and provinces of onshore and State offshore areas in the conterminous United States and Alaska.

[From the U.S. Geological Survey's 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996; Attanasi, 1998). Province numbers have leading zeros as shown below; to save space, those zeros are not shown in figure 3]

Province number	Province name
Region 1–Alaska	
001	Northern Alaska
002	Central Alaska
003	Southern Alaska
Region 2–Pacific Coast	
004	Western Oregon-Washington
005	Eastern Oregon-Washington
006	Klamath-Sierra Nevada
007	Northern Coastal
008	Sonoma-Livermore basin
009	Sacramento basin
010	San Joaquin basin
011	Central Coastal
012	Santa Maria basin
013	Ventura basin
014	Los Angeles basin
015	San Diego-Oceanside
016	Salton trough
Region 3–Colorado Plateau and Basin and Range	
017	Idaho-Snake River downwarp
018	Western Great basin
019	Eastern Great basin
020	Uinta-Piceance basin
021	Paradox basin
022	San Juan basin
023	Albuquerque-Santa Fe rift
024	Northern Arizona
025	Southern Arizona-Southwestern New Mexico
026	South-central New Mexico
Region 4–Rocky Mountains and Northern Great Plains	
027	Montana thrust belt
028	Central Montana
029	Southwest Montana
031	Williston basin
032	Sioux arch
033	Powder River Basin
034	Big Horn basin
035	Wind River Basin
036	Wyoming thrust belt
Region 4–Rocky Mountains and Northern Great Plains—Continued	
037	Southwest Wyoming
038	Park basins
039	Denver basin
040	Las Animas arch
041	Raton Basin-Sierra Grande uplift
Region 5–West Texas and Eastern New Mexico	
042	Pedernal uplift
043	Palo Duro basin
044	Permian basin
045	Bend Arch-Fort Worth basin
046	Marathon thrust belt
Region 6–Gulf Coast	
047	Western Gulf
048	East Texas basin
049	Louisiana-Mississippi salt basins
050	Florida Peninsula
Region 7–Midcontinent	
051	Superior
052	Iowa Shelf
053	Cambridge arch-central Kansas
054	Salina basin
055	Nemaha uplift
056	Forest City basin
057	Ozark uplift
058	Anadarko basin
059	Sedgwick basin
060	Cherokee basin
061	Southern Oklahoma
062	Arkoma basin
Region 8–Eastern	
063	Michigan basin
064	Illinois basin
065	Black Warrior basin
066	Cincinnati arch
067	Appalachian basin
068	Blue Ridge thrust belt
069	Piedmont
070	Atlantic Coastal Plain

Table 7. Average reservoir properties calculated for the Comprehensive Resource Database (CRD).

[Abbreviations: API, American Petroleum Institute; CO_2, carbon dioxide; H_2S, hydrogen sulfide; N_2, nitrogen]

Oil and gas reservoirs	Oil reservoirs	Gas reservoirs
Net pay (thickness)	Initial oil saturation	Initial gas saturation
Depth	Initial water saturation	Initial water saturation
Temperature gradient	Initial formation volume factor	CO_2 concentration
Pressure gradient	API gravity of oil	N_2 concentration
Porosity	Specific gravity of the gas	H_2S concentration
Permeability	Well spacing	Specific gravity of the gas
	Sulfur content	Heat content
		Sulfur content

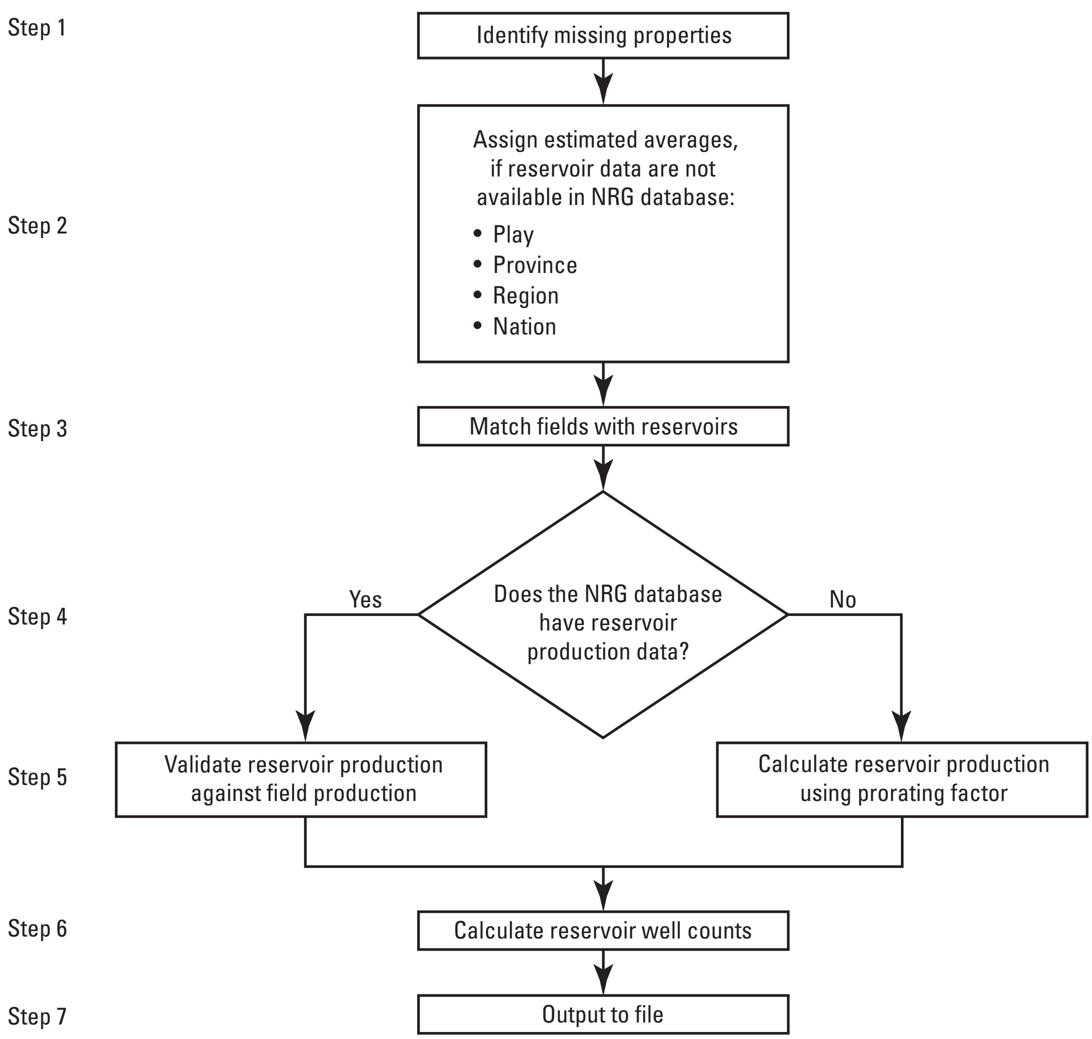

Figure 4. Chart showing the steps taken to estimate missing reservoir production data and the number of active and producing wells (well counts). Abbreviation: NRG, Nehring Associates (2012).

The averages are calculated in the following manner (equation 1):

$$playthick = \frac{\sum thick}{num\_thick} \tag{1}$$

where

playthick is the non-zero average thickness of the reservoirs in the play or province, in feet;
thick is the non-zero thickness (in feet), of the reservoir in the play or province; and
num_thick is the number of non-zero values in the play or province.

Estimation of Reservoir Production and Well Counts

The reservoir level database from Nehring Associates (2012) ("NRG") contains production data through 2010. However, it does not provide production data for all reservoirs. In the case where the production data are missing at the reservoir level, it is estimated using the production data contained in the NRG database. After the production is calculated for all reservoirs in the database, the number of active and producing wells is calculated for each reservoir. This section describes the steps taken to estimate the missing reservoir production data and the number of active and producing wells (fig. 4).

The first step shown in figure 4 is to identify the missing properties for oil and gas reservoirs. These properties determine the flow of fluids through the reservoir and include reservoir area, porosity, permeability, net pay thickness, and viscosity. If reservoir data are not available from the NRG database, then they are estimated using the following averages: play, province, region, or Nation (fig. 4, step 2).

The number of reservoirs in the field is determined by counting the number of reservoirs that share a unique field (NRG ID) (fig. 4, step 3) and then validating the reservoir production against the field production (fig. 4, step 4). If any reservoir in the field is missing production data for both oil and gas (fig. 4, step 4), three proration factors are calculated (listed in order of preference in equations 2, 3, and 4) (fig. 4, step 5); however, only one factor is chosen, based on available data:

factor one:

$$fact\_one(res) = \frac{area \times pay \times porosity \times permeability}{viscosity} \tag{2}$$

factor two:

$$fact\_two(res) = area \times pay \times porosity \times permeability \tag{3}$$

factor three:

$$fact\_three(res) = area \times pay \times porosity \tag{4}$$

where

fact_one(res) is proration factor one;
fact_two(res) is proration factor two;
fact_three(res) is proration factor three;
area is the reservoir area, in acres;
pay is the reservoir productive interval thickness, in feet;
porosity is the reservoir rock porosity, in decimal format;
permeability is the reservoir rock permeability, in millidarcies (mD); and
viscosity is the viscosity of the reservoir oil, in centipoise (cP).

After the factors have been calculated for all reservoirs in the field, reservoir distributions are calculated for each factor. The distributions are calculated as shown in equation 5.

$$dist\_(fact\_a, res) = \frac{fact\_a(res)}{\sum_{1}^{nres} fact\_a(res)} \tag{5}$$

where

dist_(fact_a,res) is the reservoir distribution factor;
fact_a is reservoir production proration factor one, two, or three;
res is the reservoir analyzed; and
nres is the number of reservoirs in the field.

The distributions are calculated using a common, complete set of proration factors. The allocation of the field production to the reservoir is determined according to equation 6.

$$respro(res,iyr) = dist\_(fact\_a,res) \times fdata(ifld,iyr) \tag{6}$$

where

respro(res,iyr)	is the annual reservoir production of oil, gas, or NGL in year analyzed (*iyr*);
res	is the reservoir analyzed;
iyr	is the year analyzed;
dist_(fact_a,res)	is the reservoir distribution factor;
fact_a	is reservoir production proration factor one, two, or three;
fdata(ifld,iyr)	is the annual field production of oil, gas, or NGL in year analyzed (*iyr*); and
ifld	is the field that is matched to the reservoir.

If reservoir production data are absent for all reservoirs in the field, or a complete set of proration factors cannot be calculated for all reservoirs matched to the field, then the production is prorated evenly among all reservoirs in the field (equation 7).

$$respro(res,iyr) = \frac{fdata(ifld,iyr)}{nres} \tag{7}$$

where

respro(res,iyr)	is the annual reservoir production of oil, gas, or NGL in year analyzed (*iyr*);
res	is the reservoir analyzed;
iyr	is the year analyzed;
fdata(ifld,iyr)	is the annual field production of oil, gas, or NGL in year analyzed (*iyr*);
ifld	is the field that is matched to the reservoir; and
nres	is the number of reservoirs in the field.

After the production is calculated for all reservoirs in the database, the number of active and producing wells (well counts) is calculated for each reservoir (fig. 4, step 6). As the well counts are provided only at the field level, they are prorated for each reservoir. The proration factors are calculated according to the distribution of production (in barrels of oil equivalent, BOE) for each reservoir in the field (equation 8).

$$reswell(res,iyr) = \frac{respro(res,iyr)}{\sum_{res=1}^{nres} respro(res,iyr)} \times fldwell(ifld,iyr) \tag{8}$$

where

reswell(res,iyr)	is the annual number of wells in the reservoir in year analyzed (*iyr*);
res	is the reservoir analyzed;
iyr	is the year analyzed;
respro(res,iyr)	is the annual production of oil, gas, or NGL converted to BOE in year analyzed (*iyr*);
nres	is the number of reservoirs in the field;
fldwell(ifld,iyr)	is the annual number of wells in the field in year analyzed (*iyr*); and
ifld	is the field that is matched to the reservoir.

The number of prorated wells is then rounded to the nearest integer. Additional steps, such as ensuring that there is a well in each year with production, are applied to ensure the reasonableness of the well count. The reservoir production data and the number of active and producing wells (well counts) are written to the CRD file (fig. 4, step 7).

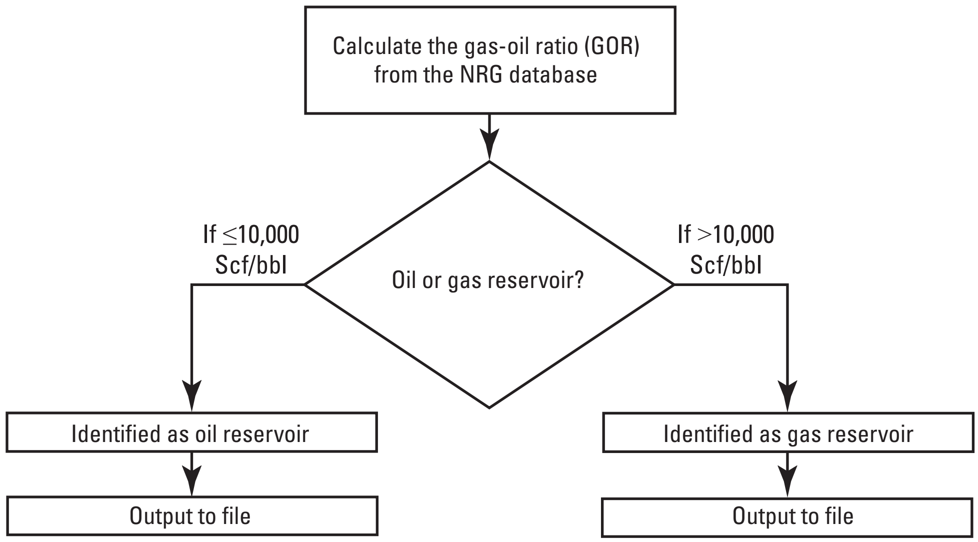

Figure 5. Flowchart showing the process for identifying reservoir type (oil or gas reservoir). Abbreviations: NRG, Nehring Associates (2012); Scf/bbl, standard cubic feet per barrel.

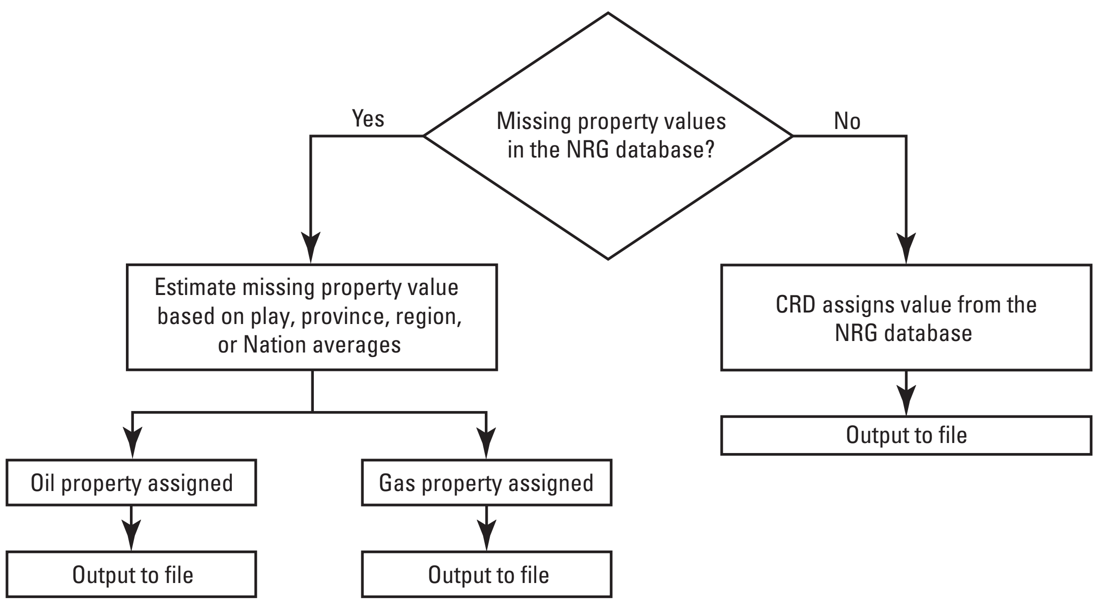

Figure 6. Flowchart showing the steps taken to estimate and calculate oil and gas property values. Abbreviations: CRD, Comprehensive Resource Database; NRG, Nehring Associates (2012).

Identify Reservoir Type

Next, as illustrated in figure 5, the reservoirs are classified as one of two types:

- Oil reservoir
- Gas reservoir

Such classification uses a calculated gas-oil ratio (GOR) based on the cumulative oil and gas production from the NRG database (fig. 5). For the purposes of EOR screening, a GOR of 10,000 Scf/bbl or less is used to define oil reservoirs and a GOR of greater than 10,000 Scf/bbl is used to define gas reservoirs. In addition, the list of existing CO_2-EOR projects (Koottungal, 2012, 2014) is used to indicate the active projects and whether the project is a miscible or immiscible CO_2 flood. During the initial reservoir type screening (fig. 5), the reservoirs are not classified as active or abandoned. This is determined after the production and well data is updated using the IHS Inc. (2012) data.

Assignment of Database Values

Next, the values of petrophysical properties for each oil and gas reservoir are checked for completeness and internal consistency. If values for the properties listed in table 7 are missing in the NRG database (fig. 6), the program estimates those values for oil or gas reservoirs using play, province, region, or Nation averages. Table 2 lists the properties for which the values are calculated or estimated as default values. Figure 6 shows the steps taken to estimate or calculate oil and gas property values.

The defaults used for estimating missing property values are derived from play, province, region, or Nation averages according to the steps provided below. Play averages are used for 28 percent of reservoir attribute records for over 22,000 reservoirs. If the reservoirs are weighted by known recovery of oil, then less than 11 percent of the oil resource uses a play average, 1.2 percent uses a province average, and 0.2 percent uses a region average. Other missing property values are estimated by calculations based on known physical relationships (not shown in fig. 6). In table 2, the missing property values that are estimated by averages are indicated by footnote 1. Other variables listed are calculated.

Average property values are determined using the following procedure:

Step 1. If the NRG has a value >0 (missing property values = "No" in fig. 6), then use the NRG value and output the value to the CRD file;

Step 2. If the NRG value equals 0 (missing property values = "No" in fig. 6), then set to play average;

Step 3. If the NRG value equals 0 and the USGS has additional data, use the USGS data. This step is applicable to pressure and temperature only;

Step 4. If the NRG value is still equal to 0, then set to province average;

Step 5. If the NRG value is still equal to 0, then set to region average;

Step 6. If the NRG value is still equal to 0, then set to Nation average;

Step 7. Output all estimated property values to the CRD file.

In addition, if USGS data are not available, then temperature and pressure require a calculation when using average NRG data.

Temperature

Step 1. If the NRG has a value greater than 0, then use the NRG value;

Step 2. If the NRG value is less than or equal to 0 and NRG has values for temperature gradient and depth, then calculate the temperature with equation 9 using the play-level default. If play-level data are not available in the NRG, then region or Nation averages may be used.

$$\mathrm{Dary}(i,17) = 60 + Ply\_TempGr(k) \times Dary(i,16) \tag{9}$$

where

Dary(i,17)	is the temperature of play, in degrees Fahrenheit (°F) in year (*i*);
i	is the year;
60	is standard temperature in degrees Fahrenheit (°F);
Ply_TempGr	is the average temperature gradient of play, in degrees Fahrenheit per foot (°F/ft);
k	is the play being analyzed; and
Dary(i,16)	is the depth of play, in feet (ft) in year (*i*).

Pressure

Step 1. If the NRG initial pressure is greater than 80 percent of the calculated pressure, then use the NRG initial pressure;

Step 2. If the NRG initial pressure is less than or equal to 80 percent of the calculated pressure, then use the calculated initial reservoir pressure (*PresCal*). The calculation is shown in equation 10 using the play-level default. If play-level data are not available in the NRG, then region or Nation averages may be used.

$$PresCal = 14.7 + Ply\_PresGr(k) \times Dary(i,16) \tag{10}$$

where

PresCal	is the calculated initial pressure, in pound-force per square inch absolute (psia);
14.7	is standard atmospheric pressure in pound-force per square inch per foot (psi/ft);
Ply_PresGr	is the average pressure gradient of play, in pound-force per square inch per foot (psi/ft);
k	is the play being analyzed;
Dary(i,16)	is the depth of play, in feet (ft) in year (*i*); and
i	is the year.

Oil Reservoir Area

Oil reservoir area is needed to calculate the original oil in place (OOIP) for reservoirs with incomplete OOIP data in the NRG database.

Step 1. If NRG has reservoir area (in acres), then use the NRG area;

Step 2. If NRG reservoir area value is ≤0, then calculate reservoir area using:

$$Area = well\ spacing \times spacing\ units \tag{11}$$

where

spacing units	is the number of wells in each reservoir with equal well spacing.

Step 3. If area is still less than or equal to 0, then calculate the reservoir area using equation 12.

$$OrgArea(i) = OOIP \times BOI / (7{,}758 \times NetPay \times (Porosity/100) \times SOI) \tag{12}$$

where

OrgArea(i)	is the calculated reservoir area, in acres in year (*i*);
OOIP	is the original oil in place, in stock tank barrels (STB);
BOI	is the initial oil formation volume factor, in decimal format;
7,758	is the conversion factor from acre-feet to barrels;
NetPay	is the net reservoir thickness, in feet (ft);
Porosity	is the porosity of the oil reservoir rock, in percent; and
SOI	is the initial oil saturation, in decimal format.

Step 4. Then, if the reservoir area is greater than the field area, use equation 13.

$$Reservoir\ area = field\ area \tag{13}$$

Well Spacing

Well spacing is needed to calculate the reservoir area (in acres) for reservoirs with incomplete well spacing data in the NRG database.

Step 1. If active wells equals 0, then set the effective well spacing equal to 0 acres;

Step 2. If there are wells, use the number of wells and the active area (in acres) to calculate the well spacing;

Step 3. Estimate the maximum well spacing, in acres:

a. If NRG provides one (of two) well spacing values, use the maximum value;

b. If the calculated value is above the maximum, use the maximum value;

c. If the well spacing has been estimated in step 3b, and if NRG provides both well spacing values, use the average value;

Step 4. If no NRG well spacing data are available, then the maximum well spacing is set as 80 acres.

Original Oil in Place

To verify that the reservoir original oil in place (*OOIP*) values in the NRG database are reasonable, the NRG *OOIP* is checked against the reservoir area, the cumulative production, and the estimated NRG known oil recovery (KR_{oil}, cumulative production plus reported reserves). Reservoir volumetric values are adjusted as necessary before a final *OOIP* calculation is made. If reservoir area is unknown, and assuming that reservoirs areas are larger than the current production area, then three times the current producing area is an initial attempt to start the iterative process of estimating area when reservoir oil recovery has already exceeded 35 percent of the NRG *OOIP*. The area was varied in the steps afterwards in order to calculate a more realistic *OOIP* than the initial *OOIP* reported in the NRG. The approach uses the following steps to calculate the reservoir *OOIP*:

Step 1. If the initial oil formation volume factor is missing, then the *OOIP* is calculated using the reservoir properties;

Step 2. Evaluate the NRG KR_{oil}:

a. If the KR_{oil} is less than or equal to 35 percent of the *OOIP*, keep the *OOIP* without any changes to the volumetric values.

b. If KR_{oil} is greater than 35 percent of the *OOIP*, then adjust the variables as follows:

i. Determine the maximum area: three times the current producing area or field area;

ii. Estimate the area necessary for a 35 percent recovery factor;

iii. If the estimated area is less than or equal to the maximum area, then set the NRG area equal to the estimated area, or;

Step 3. If the estimated area is greater than the maximum area, then set the NRG area equal to the maximum area and check *NetPay*, *Porosity*, *SOI*, and *BOI*, assuming an equal contribution of the difference and adjusting *NetPay* last;

Step 4. Allow up to 10 percent change in any of the parameters;

Step 5. Check that the revised values are within the range for the play. For example, for a given play, the minimum *SOI* is ≤ calculated *SOI* is ≤ maximum *SOI*.

Step 6. Recalculate *OOIP* using a recalculated *OrgArea(i)* using equations 14 to 16:

$$AreaOOIP = KR_{oil} \times 0.35 \tag{14}$$

where

AreaOOIP is the calculated recoverable original oil in place, in thousands of stock tank barrels (MSTB);
KR_{oil} is the NRG known oil recovery (cumulative production plus reported reserves, in thousands of barrels [Mbbl]); and
0.35 is an assumed 35 percent reservoir recovery factor.

$$OrgArea(i) = AreaOOIP \times BOI / (7,758 \times NetPay \times (Porosity/100) \times SOI) \tag{15}$$

where

OrgArea(i) is the calculated reservoir area, in acres in year (*i*);
AreaOOIP is the calculated recoverable original oil in place, in thousands of stock tank barrels (MSTB);
BOI is the initial oil formation volume factor, in decimal format;
7,758 is the conversion factor from acre-feet to barrels;
NetPay is the net reservoir thickness, in feet (ft);
Porosity is the porosity of the reservoir rock, in percent; and
SOI is the initial oil saturation, in decimal format.

$$OOIP = (7,758 \times OrgArea(i) \times NetPay \times (Porosity/100) \times SOI)/BOI \tag{16}$$

where

OOIP	is the original oil in place, in stock tank barrels (STB);
7,758	is the conversion factor from acre-feet to barrels (bbl);
OrgArea(i)	is the calculated reservoir area, in acres in year (*i*);
NetPay	is the net reservoir thickness, in feet (ft);
Porosity	is the porosity of the reservoir rock, in percent;
SOI	is the initial oil saturation, in decimal format; and
BOI	is the initial oil formation volume factor, in decimal format.

Critical Gas Reservoir Properties

Critical NRG gas reservoir properties that require estimates of missing data include (1) well spacing, (2) gas-in-place volume, (3) recovery factor, and (4) producing area. The process of estimating each property is described below.

1. Reservoir well spacing is estimated using the following steps:

   Step 1. If the number of total wells is equal to 0, set the well spacing equal to 0 acres;

   Step 2. Use well-spacing data provided by the NRG database; check that the well spacing is between 80 and 320 acres. If the well spacing is less than 80 acres, it is set equal to 80 acres. If well spacing is greater than 320 acres, it is set equal to 320 acres.

2. Reservoir gas-in-place volume per unit area (*GIPVOL*) is estimated using the following steps:

   Step 1. Calculate the gas compressibility factor (*Z factor*) following methods described in Standing and Katz (1942) and Wichert and Aziz (1971) using the gas specific gravity, its content of carbon dioxide (CO_2) and hydrogen sulfide (H_2S), reservoir pressure, and reservoir temperature;

   Step 2. Use the calculated *Z factor* to calculate the *GIPVOL* as shown in equation 17:

$$GIPVOL = \frac{43,560 \times Por \times NetPay \times SGI}{0.02829 \times Z\,factor \times (Tres + 460)} \times PRESIN \tag{17}$$

where

GIPVOL	is the original gas-in-place volume per unit area, in standard cubic feet per acre (Scf/acre);
43,560	is the conversion factor from acre-feet to cubic feet (ft^3);
Por	is the porosity of the reservoir rock, in decimal format;
NetPay	is the net reservoir thickness, in feet (ft);
SGI	is the initial gas saturation, in decimal format;
0.02829	is the conversion factor for the compressibility of gas at standard conditions (14.7 psia and 60 °F);
Z factor	is the compressibility of gas;
Tres	is the reservoir temperature, in degrees Fahrenheit (°F);
460	is the conversion factor for degrees Rankine (°R); and
PRESIN	is the initial reservoir pressure, in pound-force per square inch absolute (psia).

3. The recovery factor is estimated using the NRG known gas recovery (KR_{gas}) and the original gas in place (*OGIP*) in the following steps:

   Step 1. Divide the KR_{gas} by the *OGIP*;

   Step 2. If the reservoir is conventional, and

   - If the estimated ultimate recovery (*EUR*) is greater than 80 percent, set the recovery factor equal to 0.8;
   - If the *EUR* is less than 40 percent, set the recovery factor equal to 0.4.

   Step 3. If the reservoir is coal or shale, and

- If the *EUR* is greater than 30 percent, set the recovery factor equal to 0.3;
- If the *EUR* is less than 10 percent, set the recovery factor equal to 0.1.

4. The reservoir producing area is estimated using one of the following sequence of steps; if data are not available for an individual step, then the next step is used until the reservoir producing area has been estimated:

   Step 1. Use the gas reservoir area provided by NRG, or;

   Step 2. Use the number of wells and the well spacing provided by NRG to calculate the reservoir area, or;

   Step 3. Use the number of wells and the calculated well spacing to calculate the reservoir area, or;

   Step 4. Assume that there is only one well per 40 acres.

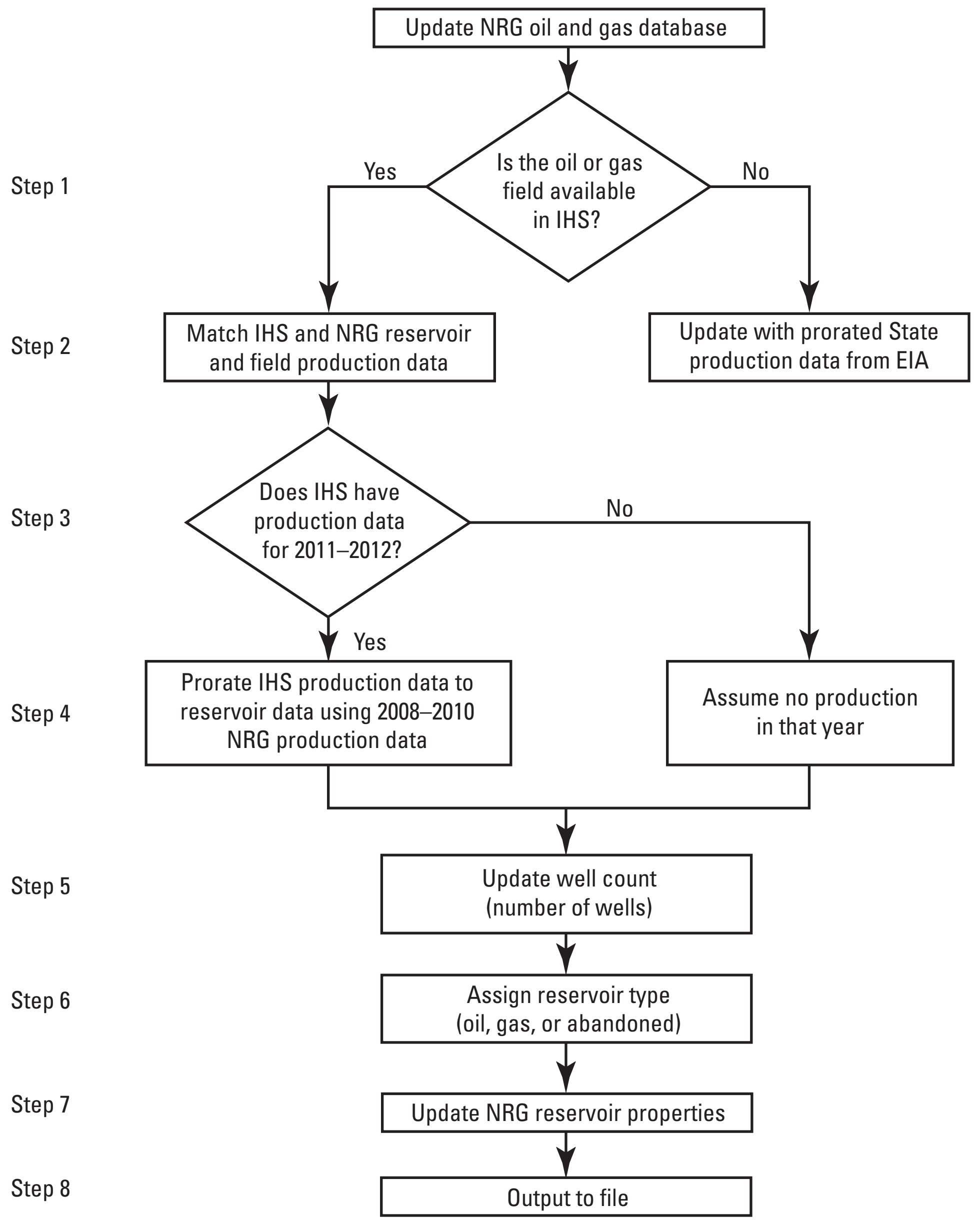

Figure 7. Flowchart showing the process steps for updating Nehring Associates (2012) production and well-count data with IHS Inc. (2012) field production and well-count data. State production data are from the U.S. Energy Information Administration (EIA, 2013a, b). Abbreviations: IHS, IHS Inc. (2012); NRG, Nehring Associates (2012).

Updating with IHS Data

As previously discussed, the NRG database production and well-count data are current through 2010. To update the data to 2012 in the CRD, the NRG database is supplemented by the IHS field production and well-count data. The major steps of this process are illustrated in figure 7 and described in this section.

Some NRG oil or gas fields that do not have IHS production data available are not subject to be updated, and no further supplementation of these fields is possible. A list of these oil or gas fields that do not have IHS data available is noted in a separate file in the CRD.

The following steps are for updating NRG production and well-count data with IHS data:

Step 1. Determine whether the IHS oil or gas field data are available. If data are not available from IHS, then the NRG production data for the CRD will be updated with prorated State production data from the U.S. Energy Information Administration (2013a, b);

Step 2. If data are available from IHS, then match IHS field and production data with NRG reservoir and field production data;

Step 3. Determine if IHS production data are available for 2011 and 2012. If no data are available for one or both years, then assume no production in that year;

Step 4. Determine how many reservoirs (and which reservoirs) are matched to the oil or gas field. For each reservoir, prorate the updated IHS oil or gas field production data using ratios calculated from the last three years (2008–2010) of the NRG production data (equation 18). A three-year period was selected in order to capture the recent production trends of the reservoirs within the field.

$$respro(res, iyr) = \frac{crespro(res)}{\sum_{res=1}^{nres} crespro(res)} \times ihsprod(ifld, iyr) \tag{18}$$

where

respro	is the annual reservoir oil or gas production, in thousands of barrels (Mbbl) or millions of cubic feet (MMcf);
res	is the reservoir analyzed;
iyr	is the year analyzed;
crespro	is the NRG cumulative production of the reservoir (2008–2010), in thousands of barrels (Mbbl) or billions of cubic feet (Bcf);
nres	is the number of reservoirs in the field;
ihsprod	is the IHS Inc. (2012) (IHS) annual oil or gas production from the field, in thousands of barrels (Mbbl) or millions of cubic feet (MMcf); and
ifld	is the field that is matched to the reservoir.

Step 5. After the production has been updated, the reservoir level well count (number of wells) is also updated, using equation 19.

$$reswell(res, iyr) = \frac{resprod(res, iyr)}{\sum_{res=1}^{nres} resprod(res, iyr)} \times fldwell(ifld, iyr) \tag{19}$$

where

reswell(res,iyr)	is the annual number of wells in the reservoir in year analyzed (*iyr*);
res	is the reservoir analyzed;
iyr	is the year analyzed;
resprod(res,iyr)	is the annual production of oil and gas, converted to barrels of oil equivalent (BOE) in year analyzed (*iyr*);
nres	is the number of reservoirs in the field;
fldwell(ifld,iyr)	is the annual number of wells in the field in year analyzed (*iyr*); and
ifld	is the field that is matched to the reservoir.

As in the previous step, the number of wells is converted to an integer and the results are checked for errors.

Step 6. Assign reservoir type as oil, gas, or abandoned;

Step 7. Update the NRG reservoir properties;

Step 8. Output the updated production data to a file for use in the CRD.

Assigning Final Reservoir Type

The updated production data is used to recalculate the gas-oil ratio (GOR) for the reservoir, and the final reservoir type is determined.

Three categories are considered for the final reservoir type assignment:

- Oil reservoir, if GOR is less than or equal to 10,000 Scf/bbl;
- Gas reservoir, if GOR is greater than 10,000 Scf/bbl;
- Abandoned reservoir, if no production is available in the last three years of data.

The oil and abandoned reservoirs are considered for CO_2-EOR in the Screening Module section of this report.

Updating Properties

In addition to updating the production and the well counts (discussed previously), several reservoir properties are updated in the NRG database (that is updated for the CRD) using IHS data. These properties are listed in table 8.

Screening Module

The screening module determines the potential oil and abandoned reservoirs, which are candidates for miscible and immiscible CO_2-EOR flooding. When CO_2 is injected under conditions of miscibility, the CO_2 aids in the recovery of oil by (1) swelling the crude oil, (2) lowering the viscosity of crude oil, and by (3) miscible displacement of the oil when the reservoir pressure is at least equal to the minimum miscibility pressure (MMP). When miscibility of two fluids occurs, the fluids are mixed with no interface between them. Miscibility of CO_2 with oil does not generally occur at the first contact, but will occur along multiple contacts if the MMP is maintained in the reservoir (Taber and others, 1997). Minimum miscibility pressure depends on the reservoir temperature, pressure, and oil composition and is calculated using curves based on experimental data that were constructed by Holm and Josendal (1974) and Mungan (1981). The curves from figure 3 of Mungan (1981) were digitized and for the CRD, the MMP was calculated by interpolation of Mungan (1981) curve values based on the CRD reservoir temperature and the molecular weight of pentanes and heavier fractions of the reservoir's oil. A list of all applied screening criteria for miscible and immiscible flooding is provided in table 9.

Outputs

The program code that generates the CRD creates 14 major outputs. These outputs contain the properties and production data for the various reservoirs evaluated by the screening criteria (table 9). Table 10 lists 14 major output files and provides a brief description of each. Included in these 14 output files that the module creates is a series of 5 "shadow" output files. The 5 shadow files identify the data sources that are used for every property value of every reservoir. These files can be used to track how the CRD computer model filled in missing property values, when an average or default was used, and if the original NRG value is retained.

Table 8. List of reservoir properties that are updated with IHS Inc. (2012) data after the final reservoir type assignment.

Oil and abandoned reservoirs	Gas reservoirs
Current oil saturation (*SOC*)	Current gas saturation (*SGC*)
Current water saturation (*SWC*)	Current water saturation (*SWC*)
Gas-oil ratio (*GOR*)	Condensate-to-gas ratio
Producing wells	Producing wells
Injection wells	Injection wells
Total wells	Total wells
Well spacing	Well spacing
Cumulative production	Cumulative production
Current oil formation volume factor (*BOC*)	Current gas formation volume factor (*BGC*)
	Current pressure
	Current temperature
	Water influx

Table 9. Screening criteria for miscible and immiscible flooding.

[Abbreviations: API, American Petroleum Institute; °API, degrees API; cP, centipoise; ft, feet; psi, pound-force per square inch]

Screening criteria properties (units)	Miscible flooding	Transitional	Immiscible flooding
API gravity of oil (°API)	[1]>25	22 > API ≤ 25	[2]13 ≤ API ≤ 22
Viscosity (cP)	[3]<10	[3]<10	[3]<10
[4]Minimum miscibility pressure (psi)	≤ fracture pressure – 400	≤ fracture pressure – 400	Not applicable

[1]National Petroleum Council (1984a).

[2]Hite (2006).

[3]Andrei and others (2010).

[4]To maintain a reasonable level of safety, the minimum miscibility pressure of candidate reservoirs must be at least 400 psi below the reservoir fracture pressure. The 400 psi safety margin is an estimate of current industry practice.

Table 10. Major output files generated in creation of the Comprehensive Resource Database (CRD).

[Abbreviations: IHS, IHS Inc. (2012); NRG, Nehring Associates (2012) database]

File name	Description
Reservoir.out	Reservoirs with backfilled/updated data; contain data based on both NRG and IHS files.
Hypothetical.out	Reservoirs with backfilled/updated data; contain data based solely on IHS files.
Oil.out	All oil reservoirs.
Gas.out	All gas reservoirs.
Abn.out	All abandoned reservoirs.
Immiscible_pot.out	Active oil reservoirs eligible for immiscible flooding.
Immiscible_abn.out	Abandoned reservoirs eligible for immiscible flooding.
Miscible_pot.out	Active oil reservoirs eligible for miscible flooding.
Miscible_abn.out	Abandoned reservoirs eligible for miscible flooding.
Shadowdata.out	Maps changes in database property values; corresponds to reservoir.out.
Shadowhypo.out	Maps changes in database property values; corresponds to hypothetical.out.
Shadowoil.out	Contains the “shadow” property values for oil.out.
Shadowgas.out	Contains the “shadow” property values for gas.out.
Shadowabn.out	Contains the “shadow” property values for abn.out.

Additional Fluid Properties in Oil Reservoirs

Current reservoir pressure (*PRESC*) is the current pressure in the reservoir after production or waterflood operations. Current reservoir pressure is calculated using equation 20:

$$PRESC = (0.433 \times DEPTH) + 14.7 \tag{20}$$

where

PRESC	is the current reservoir pressure, in pound-force per square inch absolute (psia);
0.433	is the normal hydrostatic pressure gradient for freshwater in pound-force per square inch per foot (psi/ft);
DEPTH	is the reservoir depth, in feet (ft); and
14.7	is the standard atmospheric pressure, in pound-force per square inch (psi).

However, if the initial pressure is less than current pressure, then current pressure is set equal to 90 percent of initial pressure.

Current oil saturation (*SOC*) is calculated using equation 21:

$$SOC = SOI \times \frac{\left(1 - \dfrac{cumprod}{OOIP}\right)}{\dfrac{BOC}{BOI}} \tag{21}$$

where

SOC	is the current oil saturation, in decimal format;
SOI	is the initial oil saturation, in decimal format;
cumprod	is the cumulative oil production, in thousands of barrels (Mbbl);
OOIP	is the original oil in place, in thousands of stock tank barrels (MSTB);
BOC	is the current oil formation volume factor, in decimal format; and
BOI	is the initial oil formation volume factor, in decimal format.

Initial oil formation volume factor (*BOI*) is from the NRG database, or it is calculated using the methods described in Standing (1948) and Satter and others (2008), as shown in the following steps and equations 22 to 26:

Step 1. The coefficient (*Yg*) is calculated for the solution gas-oil ratio equation (equation 22) as:

$$Yg = 0.00091 \times Tres - 0.0125 \times API \tag{22}$$

where

Yg	is the coefficient for the solution gas-oil ratio equation;
0.00091	is a constant value obtained from curve fitting by Standing (1948);
Tres	is the reservoir temperature, in degrees Fahrenheit (°F);
0.0125	is a constant value obtained from curve fitting by Standing (1948); and
API	is the American Petroleum Institute gravity of oil, in degrees API (°API).

Step 2. The solution gas-oil ratio (*RS*) is calculated using equation 23:

$$RS = SGG \times [(PRESIN/(18 \times 10^{Yg})]^{1.204} \tag{23}$$

where

RS	is the solution gas-oil ratio, in standard cubic feet per stock tank barrel (Scf/STB);
SGG	is the specific gravity of the gas;
PRESIN	is the initial reservoir pressure, in pound-force per square inch absolute (psia);
Yg	is the coefficient for the solution gas-oil ratio equation;
18	is a constant obtained by rewriting the Standing correlation equation (Standing, 1948); and
1.204	is a constant obtained by rewriting the Standing correlation equation (Standing, 1948).

Step 3. The specific gravity of oil (*SGO*) is calculated using equation 24:

$$SGO = 141.5/(131.5 + API) \qquad (24)$$

where

- *SGO* is the specific gravity of oil; and
- *API* is the American Petroleum Institute gravity of oil, in degrees API (°API) and is defined as (141.5/*SGO* at 60 °F) – 131.5.

Step 4. The coefficient *F* is calculated for the initial oil formation volume factor equation using equation 25 as:

$$F = RS \times (SGG/SGO)^{0.5}+1.25 \times Tres \qquad (25)$$

where

- *F* is the coefficient for the initial oil formation volume factor equation;
- *RS* is the solution gas-oil ratio, in standard cubic feet per stock tank barrel (Scf/STB);
- *SGG* is the specific gravity of the gas;
- *SGO* is the specific gravity of oil;
- 0.5 is a curve-fitting exponent obtained by Standing (1948);
- 1.25 is a constant value obtained from curve fitting by Standing (1948); and
- *Tres* is the reservoir temperature, in degrees Fahrenheit (°F).

Step 5. The initial oil formation volume factor (*BOI*) is calculated using equation 26:

$$BOI = 0.972 + 0.000147 \times F^{1.175} \qquad (26)$$

where

- *BOI* is the initial oil formation volume factor, in decimal format;
- 0.972 is a constant for the correlation equation developed by Standing (1948) as published in Lyons (1999);
- 0.000147 is a constant for the correlation equation developed by Standing (1948) as published in Lyons (1999);
- *F* is the coefficient for the initial oil formation volume factor equation; and
- 1.175 is a constant for the correlation equation developed by Standing (1948) as published in Lyons (1999).

Both *Tres* and *PRESIN*, in equations 22 and 23 respectively, are from the NRG database, or calculated using temperature and pressure gradients as discussed in an earlier section (equations 9 and 10).

Specific gravity of the gas (*SGG*) is provided by the NRG database or is estimated by the play or province average where its value is not provided. If no data are available, the default value of 0.8 is assumed.

Current oil formation volume factor (*BOC*) can also be calculated using equation 26 by using current reservoir temperature and pressure. If the calculated *BOC* is equal to or larger than *BOI*, then it is set equal to 99 percent of *BOI*.

Current water saturation (*SWC*) is calculated using equation 27:

$$SWC = 1 - SOC - SGI \qquad (27)$$

where

- *SWC* is the current water saturation, in decimal format;
- *SOC* is the current oil saturation, in decimal format; and
- *SGI* is the initial gas saturation, in decimal format.

Current gas saturation (*SGC*) is assumed to be the same as initial gas saturation, unless NRG data have values for initial gas saturation (*SGI*), then it is calculated using equation 28:

$$SGI = 1 - SOI - SWI \qquad (28)$$

where

- *SGI* is the initial gas saturation, in decimal format;
- *SOI* is the initial oil saturation, in decimal format; and
- *SWI* is the initial water saturation, in decimal format.

Oil viscosity (μ), if not provided in the NRG data, is calculated by first finding the dead (with no dissolved gas) oil viscosity using the Beggs and Robinson (1975) correlation (equation 29).

Dead oil viscosity (μ_DEAD) is calculated as:

$$\mu\_\text{DEAD} = 10^{X} - 1 \tag{29}$$

where

μ_DEAD	is the dead oil viscosity (no dissolved gas), in centipoise (cP); and
X	is a dummy variable that relates two other variables (°API gravity of oil and temperature) in a rather complex formula (equation 30), and is defined as:

$$X = [10^{(3.0324-(0.02023 \times API))}]/(Tres^{1.163}) \tag{30}$$

where

3.0324	is a curve-fitting exponent determined by Beggs and Robinson (1975);
0.02023	is a curve-fitting exponent determined by Beggs and Robinson (1975);
API	is the American Petroleum Institute gravity of oil, in degrees API (°API);
Tres	is the reservoir temperature, in degrees Fahrenheit (°F); and
1.163	is a curve-fitting exponent determined by Beggs and Robinson (1975).

The conversion to live oil (with dissolved gas) is based on Beggs and Robinson (1975), Vasquez and Beggs (1980), and the dead oil viscosity.

The viscosity of live oil (μ_LIVE) is calculated using equation 31:

$$\mu\_LIVE = A \times \mu\_DEAD^{B} \tag{31}$$

where

μ_LIVE	is the live oil (with dissolved gas) viscosity, in centipoise (cP);
A	is a variable coefficient whose value is determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975);
μ_DEAD	is the dead oil (no dissolved gas) viscosity, in centipoise (cP); and
B	is an exponent determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975).

A and *B* are defined in equations 32 and 33 as:

$$A = 10.715 \times (RS + 100)^{-0.515} \tag{32}$$

$$B = 5.44 \times (RS + 150)^{-0.338} \tag{33}$$

where

A	is a variable coefficient whose value is determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975);
10.715	is a constant for the correlation equation determined by Beggs and Robinson (1975);
RS	is the solution gas-oil ratio, in standard cubic feet per stock tank barrel (Scf/STB);
100	is a constant for the correlation equation determined by Beggs and Robinson (1975);
0.515	is a curve-fitting exponent determined by Beggs and Robinson (1975);
B	is an exponent determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975);
5.44	is a constant for the correlation equation determined by Beggs and Robinson (1975);
150	is a constant for the correlation equation determined by Beggs and Robinson (1975); and
0.338	is a curve-fitting exponent determined by Beggs and Robinson (1975).

CO_2 viscosity (VCO_2) is based on two-dimensional linear interpolations of CO_2 viscosity data associated with specific reservoir temperature and reservoir pressure data as presented in U.S. Department of Energy and Ministry of Energy and Mines of the Republic of Venezuela (1986).

CO_2 compressibility factor (*ZCO_2*) is based on two-dimensional linear interpolations of CO_2 compressibility factor data associated with specific reservoir temperature and pressure data, as presented in U.S. Department of Energy and Ministry of Energy and Mines of the Republic of Venezuela (1986).

Water viscosity (*VWAT*) is calculated based on the Van Wingen correlation (American Petroleum Institute, 1950) with equation 34:

$$VWAT = \exp(1.003 - 0.01479 \times Tres + 0.00001982 \times Tres^2) \tag{34}$$

where

VWAT	is the water viscosity, in centipoise (cP);
1.003	is a constant value obtained from curve fitting by Van Wingen (American Petroleum Institute, 1950);
0.01479	is a constant value obtained from curve fitting by Van Wingen (American Petroleum Institute, 1950);
Tres	is the reservoir temperature, in degrees Fahrenheit (°F); and
0.00001982	is a constant value obtained from curve fitting by Van Wingen (American Petroleum Institute, 1950).

CO_2 formation volume factor (*Bco_2*) is calculated using the dimensionless CO_2 compressibility factor (*Z factor*) (Towler, 2006) by equation 35:

$$B_{CO2} = (0.00503676) \times (Z_{CO2} \times Tres + 460)/PRESIN \tag{35}$$

where

B_{CO2}	is the CO_2 formation volume factor, in decimal format;
0.00503676	is a conversion factor for reservoir barrels per standard cubic foot (Scf);
Z_{CO2}	is the CO_2 compressibility factor, dimensionless;
Tres	is the reservoir temperature, in degrees Fahrenheit (°F);
460	is the conversion factor for degrees Rankine (°R); and
PRESIN	is the initial reservoir pressure, in pound-force per square inch absolute (psia).

Pseudo-Dykstra-Parsons coefficient (*VDP*) is computed from the calculated waterflood sweep efficiency and mobility ratio for each reservoir in the CRD database. The procedure was used for the National Petroleum Council's (NPC) 1984 study of enhanced oil recovery and followed a procedure by Robl and others (1986) and Hirasaki and others (1989). The data for the relationships between *VDP*, pseudo-volumetric sweep efficiency, and mobility ratios are presented in graphical form in Hirasaki and others (1984) and Willhite (1986). The graphical data were transferred into tabular data and interpolated with a two-dimensional function. When a *VDP* could be calculated, and if the value was between 0.1 and 0.5, it was set equal to 0.5. Values of the calculated *VDP* that exceeded 0.98 were interpreted to be the result of inconsistent reservoir or production data, or data outside of the range for the *VDP* calculation, and were set to a default value of 0.72 as suggested by Hirasaki and others (1984). For some reservoirs having insufficient data, the *VDP* value is set equal to 0, and the reservoir is no longer considered a miscible candidate.

Pseudo-volumetric sweep efficiency (*EV_1*) is defined as the ratio between the volume of oil contacted by the displacing fluid and the volume of original oil in place (Hirasaki and others, 1984; Lake, 1989) and is calculated using equation 36:

$$EV_1 = \frac{ER + (BOI/BOC) - 1.0}{(BOI/BOC)(1 - SORW/SOI)} \tag{36}$$

where

EV_1	is the pseudo-volumetric sweep efficiency, in decimal format;
ER	is the recovery factor after waterflood, in decimal format, and is estimated by the NRG known oil recovery (KR_{oil}) divided by the original oil in place (*OOIP*);
BOI	is the initial oil formation volume factor, in decimal format;
BOC	is the current oil formation factor, in decimal format;
SORW	is the residual oil saturation after waterflood, in decimal format; and
SOI	is the initial oil saturation, in decimal format.

For clastic reservoirs, the value of the residual oil saturation after waterflood (*SORW*) was set equal to 0.25 (National Petroleum Council, 1984). The original *SORW* value for carbonate reservoirs found in National Petroleum Council (1984) was later revised to 0.305 (D. Remson, U.S. Department of Energy, written commun., 2015). The value 0.305 is used in the CRD for carbonate reservoirs and the value 0.25 is used in the CRD for clastic reservoirs.

The development of EV_1 (equation 36) is only used as an internal variable to calculate the pseudo-Dykstra-Parsons coefficient (*VDP*). A second equation (equation 37), calculates the pseudo-volumetric sweep efficiency (EV_2) used in assessing the technically recoverable hydrocarbons that are producible using CO_2 enhanced oil recovery processes. EV_2 is calculated in equation 37 as:

$$EV_2 = \frac{KR_{oil} \times 1{,}000}{7{,}758 \times Area \times NetPay \times Por \times \left[\frac{SOI}{BOI} - \frac{SORW}{BOC} \right]} \tag{37}$$

where

EV_2 is the pseudo-volumetric sweep efficiency, in decimal format;
KR_{oil} is the NRG known oil recovery (cumulative production plus reported reserves), in thousands of barrels (Mbbl);
1,000 is the conversion factor needed to convert KR_{oil} to barrels (bbl);
7,758 is the conversion factor from acre-feet to barrels (bbl);
Area is the reservoir area, in acres;
NetPay is the net reservoir thickness, in feet (ft);
Por is the porosity of the reservoir rock, in decimal format;
SOI is the initial oil saturation, in decimal format;
SORW is the residual oil saturation after waterflood, in decimal format;
BOI is the initial oil formation volume factor, in decimal format; and
BOC is the current oil formation volume factor, in decimal format.

Gas Reservoir and Fluid Properties

Current reservoir pressure (*PRESC*) for gas reservoirs is calculated the same as for oil reservoirs (equation 20).

Current gas saturation (*SGC*) is calculated using equation 38, when the initial gas formation volume factor (*BGI*) and the original gas in place (*OGIP*) are greater than zero:

$$SGC = \frac{OGIP - cumprod}{OGIP} \times SGI \times \frac{BGC}{BGI} \tag{38}$$

where

SGC is the current gas saturation, in decimal format;
OGIP is the original gas in place, in billions of cubic feet (Bcf);
cumprod is the cumulative gas production, in billions of cubic feet (Bcf);
SGI is the initial gas saturation, in decimal format;
BGC is the current gas formation volume factor, in decimal format; and
BGI is the initial gas formation volume factor, in decimal format.

Original gas in place (*OGIP*) is calculated in equation 39 as:

$$OGIP = GIPVOL \times area \tag{39}$$

where

OGIP is the original gas in place, in standard cubic feet (Scf);
GIPVOL is the original gas-in-place volume per unit area, in standard cubic feet per acre (Scf/acre); and
area is the reservoir area, in acres.

Original gas-in-place volume per reservoir area (*GIPVOL*) for conventional reservoirs is calculated in equation 40 as:

$$GIPVOL = \frac{43{,}560 \times Por \times NetPay \times SGI}{0.02829 \times Z_i \times (Tres + 460)} \times PRESIN \tag{40}$$

where

GIPVOL is the original gas-in-place volume per reservoir area, in standard cubic feet per acre (Scf/acre);
43,560 is the conversion factor from acre-feet to cubic feet (ft^3);
Por is the porosity of reservoir rock, in decimal format;
NetPay is the net reservoir thickness, in feet (ft);
SGI is the initial gas saturation, in decimal format;
0.02829 is the conversion factor for the compressibility of gas at standard conditions (14.7 psia and 60 °F);

Z_i is the initial gas compressibility factor;
460 is the conversion factor for degrees Rankine (°R);
Tres is the reservoir temperature, in degrees Fahrenheit (°F); and
PRESIN is the initial reservoir pressure, in pound-force per square inch absolute (psia).

Initial gas formation volume factor (*BGI)* is calculated in equation 41 as:

$$BGI = \frac{520 \times PRESIN}{14.7 \times Z_i \times (Tres_i + 460)} \tag{41}$$

where
BGI is the initial gas formation volume factor, in decimal format;
520 is the coefficient for the current gas formation volume factor;
PRESIN is the initial reservoir pressure, in pound-force per square inch absolute (psia);
14.7 is the standard atmospheric pressure, in pound-force per square inch (psi);
Z_i is the initial gas compressibility factor;
$Tres_i$ is the initial reservoir temperature, in degrees Fahrenheit (°F); and
460 is the conversion factor for degrees Rankine (°R).

Current gas formation volume factor (*BGC*) is calculated in equation 42 as:

$$BGC = \frac{520 \times PRESC}{14.7 \times Z_c \times (Tres_c + 460)} \tag{42}$$

where
BGC is the current gas formation volume factor, in decimal format;
520 is the coefficient for the current gas formation volume factor;
PRESC is the current reservoir pressure, in pound-force per square inch absolute (psia);
14.7 is the standard atmospheric pressure, in pound-force per square inch (psi);
Z_c is the current gas compressibility factor;
$Tres_c$ is the current reservoir temperature, in degrees Fahrenheit (°F); and
460 is the conversion factor for degrees Rankine (°R).

Generally, Z_c is assumed to be equal to the initial gas compressibility factor (Z_i).

Initial pressure for gas reservoirs (*PRESIN*) is calculated with the same procedure as for the oil reservoir initial pressure in the absence of values in the NRG database.

Current pressure for gas reservoirs (*PRESC*) is calculated using equation 43, where Z_c is assumed to be equal to Z_i:

$$\frac{PRESC}{Z_c} = \frac{PRESIN}{Z_i} \times \left(1 - \frac{cumprod}{OGIP}\right) \tag{43}$$

where
PRESC is the current reservoir pressure, in pound-force per square inch absolute (psia);
PRESIN is the initial reservoir pressure, in pound-force per square inch absolute (psia);
cumprod is the cumulative gas production, in billions of cubic feet (Bcf);
Z_c is the current gas compressibility factor;
Z_i is the initial gas compressibility factor; and
OGIP is the original gas in place, in billions of cubic feet (Bcf).

Initial gas compressibility factor (Z_i) is calculated as a function of the specific gravity of gas, its content of carbon dioxide (CO_2) and hydrogen sulfide (H_2S), reservoir pressure, and reservoir temperature, and is based on correlations described in Standing and Katz (1942) and Wichert and Aziz (1971).

Specific gravity of the gas (*SGG*) is provided by the NRG database, or if the value is not provided in the NRG database, it is estimated by the play or province average. If average data are not available the default value is 0.8.

Reservoir water influx volume (*WATIN*) is calculated by equation 44 as:

$$WATIN = cumprod \times BGC - OGIP \times (BGC - BGI) \tag{44}$$

where

WATIN is the reservoir water influx volume, in billions of cubic feet (Bcf);
cumprod is the cumulative gas production, in billions of cubic feet (Bcf);
BGC is the current gas formation volume factor, in decimal format;
OGIP is the original gas in place, in billions of cubic feet (Bcf); and
BGI is the initial gas formation volume factor, in decimal format.

Estimated ultimate recovery (*EUR*) for gas reservoirs is calculated with equation 45 (in the equation the contaminant gases, CO_2, N_2, and H_2S are in molecular percent of the total gas in the reservoir):

$$EUR = \frac{KR_{gas}}{(100 - \mathrm{CO_2} - \mathrm{N_2} - \mathrm{H_2S})} + 1.302 \times KR_{NGL} \tag{45}$$

where

EUR is the estimated ultimate recovery, in billions of cubic feet (Bcf);
KR_{gas} is the NRG known gas recovery (cumulative production plus reported reserves), in millions of cubic feet (MMcf);
CO_2 is carbon dioxide;
N_2 is nitrogen;
H_2S is hydrogen sulfide;
1.302 is the natural gas liquids (*NGL*) conversion factor; and
KR_{NGL} is the NRG known natural gas liquids (*NGL*) recovery (cumulative production plus reported reserves) in thousands of barrels (Mbbl).

The *EUR* is the raw gas volume and includes the gas contaminants CO_2, N_2, and H_2S. The KR_{gas} and KR_{NGL} data are in the form of marketable gas (cumulative production plus reported reserves) and natural gas liquids, as reported in the NRG database at the end of 2010. All KR_{gas} and KR_{NGL} data used as inputs to the equations are from NRG database. The natural gas liquids (*NGL*) conversion factor converts barrels (bbl) to thousands of cubic feet (Mcf) using volume, and it is used to convert *NGL* to dry gas using British thermal units (Btu). These conversions are derived using equation 46:

$$1.302 = \frac{5.614}{\left(\frac{5.418}{1.250}\right)} \tag{46}$$

where

1.302 is the natural gas liquids (*NGL*) conversion factor;
5.614 is the assumed cubic feet of gas per barrel of oil;
5.418 is million British thermal units per barrel of plant condensate (U.S. Energy Information Administration, 2012); and
1.250 is the assumed average British thermal units per cubic foot (Btu/ft^3) of liquids-rich dry gas (Braziel, 2012).

Gas reservoir recovery factor (*RECY*) is calculated using equation 47 as:

$$RECY = \frac{EUR}{ACPROD \times GIPVOL} \tag{47}$$

where

RECY is the gas reservoir recovery factor, in decimal format;
EUR is the estimated ultimate recovery, in standard cubic feet (Scf);
ACPROD is the producing area, in acres; and
GIPVOL is the original gas-in-place volume per unit area, in standard cubic feet per acre (Scf/acre).

Summary

The Comprehensive Resource Database (CRD) was developed to support hydrocarbon assessments prepared by the U.S. Geological Survey (USGS). The CRD contains the location, key petrophysical properties, production, and well counts for the major oil and gas reservoirs in the onshore and State waters areas of the conterminous United States and Alaska. The data within the CRD cannot be released to the public because it includes proprietary field and reservoir petrophysical property data from the Nehring Associates (2012) "Significant Oil and Gas Fields of the United States Database" and proprietary production and drilling data from "Petroleum Information Data Model Relational U.S. Well Data" prepared by IHS Inc. (2012). This report provides a description of (1) the CRD computer program and its methodology, (2) a list of the key data sources used in its development, (3) a description of the steps and routines used to prepare the CRD, (4) the screening criteria for miscible or immiscible CO_2 flooding applied to the CRD, (5) the database outputs, and (6) documentation of the computational procedures that were applied. The equations used in the calculations, a list of the input and output reservoir property data and variables, the computer code, and the CRD are on file at the USGS Eastern Energy Resources Science Center located in Reston, Va.

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