

National and Global Petroleum Assessment

# Assessment of Undiscovered Conventional Oil and Gas Resources in Postsalt Reservoirs of the West-Central Coastal Province of Africa, 2022

Using a geology-based assessment methodology, the U.S. Geological Survey estimated undiscovered, technically recoverable mean conventional resources of 10.5 billion barrels of oil and 47.4 trillion cubic feet of gas in postsalt reservoirs within the West-Central Coastal Province of Africa.

## Introduction

The U.S. Geological Survey (USGS) assessed undiscovered, technically recoverable conventional oil and gas resources in the Douala-Rio Muni, Gabon, Congo, Kwanza-Benguela, and Namibe Basins of the West-Central Coastal Province of Africa (fig. 1). The assessment focused on the potential for undiscovered conventional oil and gas resources in reservoirs that are stratigraphically younger than the regionally extensive layer of late Aptian salt (“postsalt” reservoirs).

The tectonic evolution of the West-Central Coastal Province began with the separation of Africa from South America in the Late Jurassic to Early Cretaceous (Torsvik and others, 2009; Guiraud and others, 2010; Matos and others, 2021; Matos, 2021). Rifting formed a broad, complex region of horsts and grabens that occur throughout the length of the West Central Coastal Province (Jackson and Hudec, 2009; Baudino and others, 2018). As rifting waned in the Early Cretaceous, thermal subsidence formed accommodation space (or “sag”) that filled with regionally extensive fluvial and lacustrine sediments. A series of transgressions beginning in the late Aptian caused marine waters to intermittently flow over the Walvis Ridge and across extended continental crust where evaporation led to the deposition of more than 1 kilometer of late Aptian salt (Greenhalgh and others, 2012). The cessation of rifting was followed by initiation of seafloor spreading in latest Aptian and the passive margin phase of west-central Africa. Transgression in the Albian formed extensive carbonate platforms with deposition of off-platform mudstones and marls, including Cenomanian to Turonian organic-rich shales. Santonian to Eocene deposition along the margin alternated between thin, prograding clastic sequences and carbonate platforms. Uplift of the cratonic margin in the Oligocene resulted in a major progradation of clastic sequences that provide most of the major reservoirs in the Mesozoic–Cenozoic Total Petroleum System. The definitions of assessment units were based on this general framework of reservoir development. Cretaceous carbonates were separated into assessment units, as were Paleogene and Neogene siliciclastic sequences.

## Total Petroleum System and Assessment Units

The USGS defined a Mesozoic–Cenozoic Composite Total Petroleum System (TPS) and 10 conventional assessment units (AUs) within this TPS (fig. 1). The AUs in general share similar petroleum system elements of source rocks, reservoirs rocks, trap types, seals, and timing of oil and gas generation and migration (Beglinger and others, 2012), but the elements differ in detail between basins. Hydrocarbon source rocks within the Mesozoic–Cenozoic Composite TPS include Berriasian to Barremian synrift organic-rich lacustrine shales with

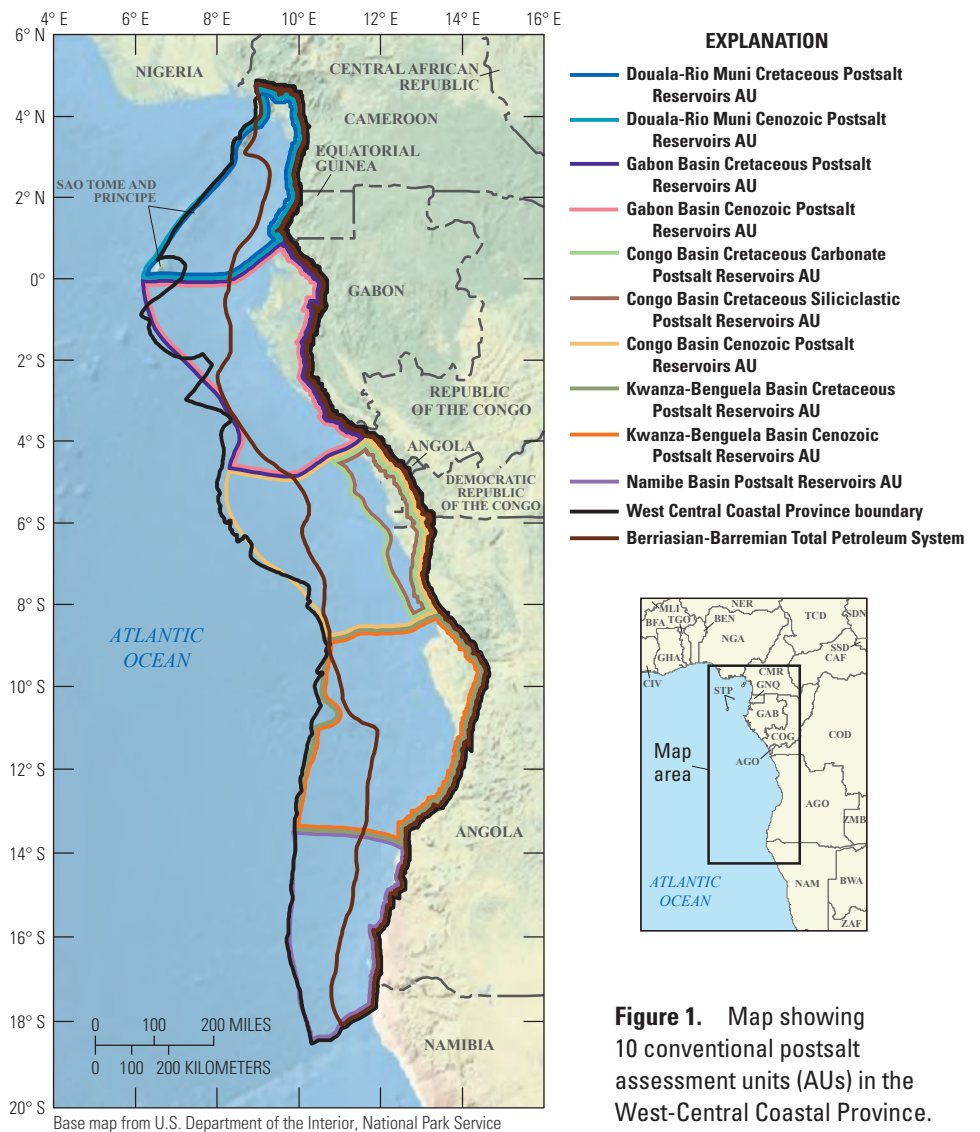


Figure 1. Map showing 10 conventional postsalt assessment units (AUs) in the West-Central Coastal Province.

Type I and II organic matter, have total organic carbon (TOC) content up to 20 weight percent, have hydrogen index (HI) values up to 800 milligrams of hydrocarbon per gram of TOC (mg HC/g TOC), and are as much as 600 meters (m) thick (Brownfield and Charpentier, 2006; Greenhalgh and others, 2012). Cenomanian to Turonian source rocks have Type II marine organic matter, have up to 10 weight percent TOC, have HI values up to 450 mg HC/g TOC, and are up to 30 m thick (Anka and others, 2010). Paleocene to Miocene shales have mixed Types II/III organic matter, have TOC values up to 5 weight percent, have HI values up to 400 mg HC/g TOC, and are as much as 40 m thick.

Postsalt reservoirs include Albian to Coniacian platform-margin carbonate reservoirs, including reefs, buildups, dolomites, and karst zones (Fort and others, 2004; Guiraud and others, 2010). Clastic sediments that bypassed the platforms during sea-level lowstands formed minor slope-channel and basin-floor reservoirs. Santonian to Eocene progradation of clastic systems during an overall sea-level highstand resulted in shelf, slope-channel, and basin-floor sandstones encased in shales. A major clastic sequence prograded offshore beginning in the Oligocene. This sequence was related to uplift and westward tilting of the cratonic margin. Extensive stacked slope-channel and basin-floor fan reservoirs that were deposited during this time form the major oil and gas reservoirs in the

Congo, Gabon, and Kwanza-Benguela Basins. Deformation of Aptian salt was concurrent with the progradation of clastic sequences since the Albian, which influenced sediment transport pathways, depositional sites of sandstones, and formation of minibasins (Brownfield and Charpentier, 2006). Salt deformation was caused by sediment loading and by gravitational sliding as the cratonic margin was uplifted and tilted westward, notably during the Albian to Cenomanian and the Oligocene to Holocene.

Traps throughout the Mesozoic–Cenozoic Composite TPS are strongly influenced by continuous salt deformation. Traps within Cretaceous carbonates are mainly stratigraphic, but structural traps were created by the downslope movement and subsequent deformation of carbonate blocks. The progradation of clastic sequences occurred coeval with salt mobilization, in which salt diapirs, pillars, and overhangs influenced sediment transport paths and depositional sites, especially for slope-channel and basin-floor fans. Gravity sliding of salt created extensional traps updip, and contractional structures downdip, including folds, faults, anticlines, and thrust structures within the sandstones (Fort and others, 2004). Most structures have potentially been modified by continuous salt movement, and fluid movement likewise may also be continuous (Andresen and others, 2011; Anderson and others, 2012), leading to remigration or potential loss of fluids.

**Table 1.** Key input data for 10 conventional postsalt assessment units in the West Central Coastal Province.

[Gray shading indicates not applicable. AU, assessment unit; MMBO, million barrels of oil; BCFG, billion cubic feet of gas]

Assessment input data— Conventional AUs	Douala-Rio Muni Cretaceous Postsalt Reservoirs AU				Douala-Rio Muni Cenozoic Postsalt Reservoirs AU			
	Minimum	Median	Maximum	Calculated mean	Minimum	Median	Maximum	Calculated mean
Number of oil fields	1	20	60	21.3	1	20	60	21.3
Number of gas fields	1	20	60	21.3	1	20	60	21.3
Size of oil fields (MMBO)	5	8	500	15.9	5	8	500	15.9
Size of gas fields (BCFG)	30	48	4,000	105.4	30	48	2,500	89.8
AU probability	1.0				1.0			
Assessment input data— Conventional AUs	Gabon Basin Cretaceous Postsalt Reservoirs AU				Gabon Basin Cenozoic Postsalt Reservoirs AU			
	Minimum	Median	Maximum	Calculated mean	Minimum	Median	Maximum	Calculated mean
Number of oil fields	1	40	80	41.0	1	30	60	30.7
Number of gas fields	1	20	40	20.5	1	30	60	30.7
Size of oil fields (MMBO)	5	8	1,000	20.5	5	8	100	10.5
Size of gas fields (BCFG)	30	48	10,000	154.1	30	48	4,000	105.4
AU probability	1.0				1.0			
Assessment input data— Conventional AUs	Congo Basin Cretaceous Carbonate Postsalt Reservoirs AU				Congo Basin Cretaceous Siliciclastic Postsalt Reservoirs AU			
	Minimum	Median	Maximum	Calculated mean	Minimum	Median	Maximum	Calculated mean
Number of oil fields	1	30	90	31.9	1	30	90	31.9
Number of gas fields	1	20	60	21.3	1	20	60	21.3
Size of oil fields (MMBO)	5	8	1,000	20.5	5	8	4,000	40.1
Size of gas fields (BCFG)	30	48	6,000	123.3	30	48	10,000	154.1
AU probability	1.0				1.0			
Assessment input data— Conventional AUs	Congo Basin Cenozoic Postsalt Reservoirs AU				Kwanza-Benguela Basin Cretaceous Postsalt Reservoirs AU			
	Minimum	Median	Maximum	Calculated mean	Minimum	Median	Maximum	Calculated mean
Number of oil fields	1	60	120	61.5	1	50	150	53.2
Number of gas fields	1	30	60	30.7	1	50	150	53.2
Size of oil fields (MMBO)	5	8	4,000	40.1	5	8	4,000	40.1
Size of gas fields (BCFG)	30	48	10,000	154.1	30	48	8,000	139.3
AU probability	1.0				1.0			
Assessment input data— Conventional AUs	Kwanza-Benguela Basin Cenozoic Postsalt Reservoirs AU				Namibe Basin Postsalt Reservoirs AU			
	Minimum	Median	Maximum	Calculated mean	Minimum	Median	Maximum	Calculated mean
Number of oil fields	1	60	120	61.5	1	20	60	21.3
Number of gas fields	1	30	60	30.7	1	20	60	21.3
Size of oil fields (MMBO)	5	8	2,000	28.0	5	8	1,000	20.5
Size of gas fields (BCFG)	30	48	6,000	123.3	30	48	6,000	123.3
AU probability	1.0				1.0			

The differences in sediment thicknesses and burial, heat flow, and source-rock quality and distribution across the composite TPS led to spatial and temporal variations in thermal maturity. In general, the synrift lacustrine source rocks reached maturity for oil generation in the Aptian; oil generation may have begun from synrift lacustrine shales in the Aptian, and gas generation may have begun in the Oligocene (Brownfield and Charpentier, 2006).

The AUs defined in this assessment are based on the tectonic and stratigraphic evolution of the West-Central Coastal Province. To reflect the different groups and types of postsalt reservoir strata that were deposited during the Cretaceous and in the Paleogene to Neogene, the Douala-Rio Muni Cretaceous Postsalt Reservoirs AU, the Douala-Rio Muni Cenozoic Postsalt Reservoirs AU, the Gabon Basin Cretaceous Postsalt Reservoirs AU, the Gabon Basin Cenozoic Postsalt Reservoirs AU, the Congo Basin Cretaceous Carbonate Postsalt Reservoirs AU, the Congo Basin Cretaceous Siliciclastic Postsalt Reservoirs AU, the Congo Basin Cenozoic Postsalt Reservoirs AU, the Kwanza-Benguela Cretaceous Postsalt Reservoirs AU, the Kwanza-Benguela Cenozoic

Postsalt Reservoirs AU, and the Namibe Basin Postsalt Reservoirs AU were defined within the Mesozoic–Cenozoic Composite TPS (fig.1). Assessment input data are summarized in table 1 and in Schenk (2024).

## Undiscovered Resources Summary

The USGS quantitatively assessed oil and gas resources in 10 conventional AUs in five basins of the West-Central Coastal Province (table 2). For undiscovered, technically recoverable conventional oil and gas resources, the mean totals are 10,518 million barrels of oil (MMBO), or 10.5 billion barrels of oil, with an F95 to F5 fractile range from 3,759 to 22,446 MMBO; 47,411 billion cubic feet of gas (BCFG), or 47.4 trillion cubic feet of gas, with an F95 to F5 fractile range from 17,311 to 100,896 BCFG; and 1,059 million barrels of natural gas liquids (MMBNGL), or 1.0 billion barrels, with an F95 to F5 fractile range from 384 to 2,258 MMBNGL.

**Table 2.** Results for 10 conventional postsalt assessment units in the West-Central Coastal Province.

[Results shown are fully risked estimates. F95 represents a 95-percent chance of at least the amount tabulated; other fractiles are defined similarly. Gray shading indicates not applicable. MMBO, million barrels of oil; BCFG, billion cubic feet of gas; NGL, natural gas liquids; MMBNGL, million barrels of natural gas liquids]

Total petroleum system and assessment units (AUs)	AU probability	Accumulation type	Total undiscovered resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Mesozoic–Cenozoic Total Petroleum System														
Douala-Rio Muni Cretaceous Postsalt Reservoirs AU	1.0	Oil	129	300	677	337	128	300	679	338	3	6	14	7
		Gas					803	1,951	4,686	2,240	22	53	127	60
Douala-Rio Muni Cenozoic Postsalt Reservoirs AU	1.0	Oil	128	298	681	337	307	717	1,631	810	4	10	23	11
		Gas					764	1,706	3,727	1,909	29	65	142	73
Gabon Basin Cretaceous Postsalt Reservoirs AU	1.0	Oil	391	769	1,552	844	429	845	1,714	928	7	14	29	16
		Gas					1,060	2,527	7,572	3,156	32	76	227	95
Gabon Basin Cenozoic Postsalt Reservoirs AU	1.0	Oil	202	313	474	322	180	281	429	289	1	2	3	2
		Gas					1,542	2,954	5,894	3,232	32	62	124	68
Congo Basin Cretaceous Carbonate Postsalt Reservoirs AU	1.0	Oil	230	569	1,366	653	550	1,366	3,279	1,568	21	52	125	60
		Gas					841	2,197	5,890	2,612	24	62	165	73
Congo Basin Cretaceous Siliciclastic Postsalt Reservoirs AU	1.0	Oil	298	970	3,351	1,275	357	1,162	4,028	1,530	16	52	181	69
		Gas					898	2,584	8,098	3,270	4	10	32	13
Congo Basin Cenozoic Postsalt Reservoirs AU	1.0	Oil	901	2,127	5,238	2,477	807	1,912	4,707	2,230	5	12	28	13
		Gas					1,802	4,024	10,264	4,743	38	85	216	100
Kwanza-Benguela Basin Cretaceous Postsalt Reservoirs AU	1.0	Oil	589	1,750	4,883	2,115	707	2,100	5,851	2,537	14	42	117	51
		Gas					2,750	6,637	14,750	7,416	72	172	384	193
Kwanza-Benguela Basin Cenozoic Postsalt Reservoirs AU	1.0	Oil	751	1,555	3,237	1,721	747	1,556	3,239	1,720	6	12	26	14
		Gas					1,653	3,360	7,409	3,789	35	71	156	80
Namibe Basin Postsalt Reservoirs AU	1.0	Oil	140	365	987	437	154	402	1,089	481	2	5	13	6
		Gas					832	2,183	5,960	2,613	17	46	126	55
<b>Total undiscovered conventional postsalt resources</b>			<b>3,759</b>	<b>9,016</b>	<b>22,446</b>	<b>10,518</b>	<b>17,311</b>	<b>40,764</b>	<b>100,896</b>	<b>47,411</b>	<b>384</b>	<b>909</b>	<b>2,258</b>	<b>1,059</b>

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## For More Information

Assessment results are also available at the USGS Energy Resources Program website at <https://www.usgs.gov/energy-and-minerals/energy-resources-program/>.

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