New reservoir-quality index forecasts field well-productivity worldwide

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Differences exist between two approaches to measuring field decline that could significantly affect appraisals. Field well-productivity performance is a more accurate measure than the industry practice of calculating decline rate based only on production.

Operators monitor field well-productivity. The index outlined by this article offers a method for executives to determine reservoir quality and make decisions about a field's economic feasibility.

The index assesses both reservoir quality and reserves quantities.

This index analyzes field well-productivity across giant oil fields such as Ghawar in Saudi Arabia and Safaniya offshore Saudi Arabia, and Karachaganak gas-condensate field in Kazakhstan. The analysis encompasses 18 oil-producing countries.

Field well-productivity is the ratio of a field's production to the number of producing wells. The study sought to determine possible patterns between peak well-productivity and established static geologic and reservoir parameters.

The index provides a compendium of core geologic parameters, well-productivities rates, and decline rates for some of the world's most productive oil fields. High well-productivity per field offsets mounting development costs associated with exploration efforts worldwide.

Field well-productivity establishes average well reserves, future drilling requirements to maintain field production levels, and future field performance. It accounts for reservoir decline, setting it apart from well-productivity of individual wells. Field well-productivity also has a characteristic exponential decline that enables the use of simple analytic tools for calculating the reserves and production rates required in field appraisals.

Operators use field well-productivity for a more sensitive measure than production rate to establish accurate peak production for both conventional and tight oil plays (OGJ, Nov. 3, 2014, p. 66).

WELL-PRODUCTIVTIES OF MAJOR OIL PRODUCING FIELDS

Country, field, year discovered	Formation	Age	Water depth, ft[1]	Reservoir depth, ft	Pore-pressure[2] gradient, psi/ft	Net thickness, ft	Lithology	Deposition
US								
Thunder Horse, 1999	Pre-salt	Miocene	6,000	19,700	0.72	520	Turbidite sands	Deep water
Jack/St. Malo, 2003	Pre-salt	Oligocene	7,000	19,400	0.6	350	Sandstone, sandstone	Deep water
Bakken, 2000	Tight oil	Devonian	—	3,100-11,000	0.5	105	Siltstone, sandstone	Deltaic
Eagle Ford, 1962	Tight oil	Cretaceous	—	2,500-15,000	0.65	200	Shale, sandstone	Shallow marine
Spraberry, 1949	Tight oil	Permian	—	6,800	0.42	500	Siltstone, sandstone	Deep water
Prudhoe Bay, 1967	Sadlerochit	Triassic	—	8,800	0.493	500	Sandstone	Deltaic
Canada								
Cold Lake, 1966	Oil Sands	Cretaceous	1,640	1,640	0.45	170	Unconsolidated, sandstone	Tidal
Hibernia, 1979	Hibernia	Cretaceous	260	11,900	0.44	450	Unconsolidated, sandstone	Deltaic
Pembina, 1953	Cardium	Cretaceous	—	3,865	0.45	70	Sandstone	Tidal
Mexico								
Cantarell, 1976	Sihil	Cretaceous	105	8,423	0.45	500	Carbonate	Meteoric
Samaria, 1973	Tamabra	Cretaceous	—	13,120	0.6	300	Carbonate	Shallow marine
Venezuela								
Tia Juana, 1928	Lagunillas	Miocene	—	2,000	0.43	120	Sandstone	Deltaic
Lama, 1957	Misoa	Eocene	160	8,140	0.45	700	Sandstone	Deltaic
Furrial, 1986	Naricual	Oligocene	—	14,772	0.74	905	Sandstone	Deltaic
Petrozuata ,1995	Oil Sands	Miocene	—	1,700	0.44	350	Unconsolidated, sandstone	Deltaic

Some fields have maintained high production rates for unusually long periods–mostly by in-fill drilling–even after peak production. China's Daqing field sustained production above 1 million b/d for over 35 years. The use of field well-productivity to measure peak production helps explain production rates.

Methodology

Fig. 1 shows well-productivity profiles from peak year to the present for several major producing countries. Big differences exist in regional well-productivity.

Although this chart is akin to production profiles, well-productivity that couples production with the number of producing wells offers a distinct advantage in that its profiles are a straight line in log-linear space, providing a relatively quick look at decline behavior.

Declines vary by country from moderate to high. The straight-line characteristic is interrupted only by major technological advances such as the recent tight-oil successes in the US, reflected by a noticeable jump in the trend line starting in 2008 when crude oil production rose 1.1 million b/d/year through December 2015.

Neither of the two additional points shown on this trend line—1978 for Alaska's production start and 2001 for the start of the Gulf of Mexico deepwater production—affected the straight-line trend.

Several geologic and reservoir parameters influence well-productivity in oil fields. Geologic factors include formation, age, depth, depositional style, lithology, net pay, and heterogeneity of the primary producing interval of each field. Reservoir factors are porosity, permeability, pore-pressure gradient, and crude gravity.

Statistics were obtained from information published by the American Association of Petroleum Geologists, the Society of Petroleum Engineers, and Oil & Gas Journal, dating back to the 1950s.

Data on field production and production wells came from the Worldwide Production Survey (OGJ, Dec. 6, 2014). Most was verified from more than one source.

The accompanying table summarizes the static parameters plus a couple of key dynamic attributes—well productivity and field decline rates—of the 34 oil fields in the study. The addition of a second well-productivity value helped determine decline rates for fields having sufficient production history. The table includes the calculated values of each field's reservoir quality index (RQI).

The table is the study's center piece. It provides perspective on the type and quality of petroleum systems that support high-quality reservoir performance in the world's best oil fields.

Parameters

Thirteen of 29 fields analyzed are onshore and have peak field well-productivity values of less than 8,000 b/d/well. The exception is Ghawar. Its field well-productivity peaked

Porosity, %	Permeability, md	Heterogeneity, net/gross pay	Gravity	Reservoir quality index	Production, b/d	Year	Producing wells	Well-productivity, b/d/well	Field decline rate/year, %
23	750	0.76	34	49	202,000	2009*	9	22,400	
					65,000	2014	9	7,220	23
23	< 10	0.32	30	0.1	75,000	2016	9	8,300	—
12	< 0.1	0.77	42	< 0.001	472,000	2011*	3,275	144	—
					860,000	2013	6,824	126	7
10	< 0.1	0.75	42	< 0.001	130,000	2011*	480	270	—
					717,000	2013	5,493	130	36
12	< 0.5	0.5	41	0.1	70,000	1980	1,850	38	—
					108,000	2009	9,000	12	4
22	500	0.87	28	23	1,627,000	1987*	690	2,357	—
					325,000	2005	384	846	6
33	>1,000	0.25	< 12	6	147,000	2008*	8,000	18	—
20	950	0.7	36	26	144,000	2000*	10	14,400	—
					115,000	2014	27	4,260	9
10	4	0.7	34	0.01	112,000	1970*	3,249	35	—
					48,000	2000	3,330	14	3
10	>1,000	0.76	22	17	1,000,000	1981*	50	20,000	—
					1,000,000	1996	139	7,200	7
6	100	0.7	30	1	314,000	1978*	40	7,850	—
					52,000	2012	115	452	8
20	610	0.50e	18	3	384,000	1970*	1,383	280	—
					236,000	1995	1,937	120	3
22	300	0.50e	32	10	382,000	1970*	182	2,100	—
					141,000	1980	196	720	11
14	600	0.56	28	32	454,000	1998*	150	3,000	—
					355,000	2001	163	2,200	10
35	> 1,000	0.18	< 12	10	109,000	2000*	120	900	—
					113,000	2008	305	370	11

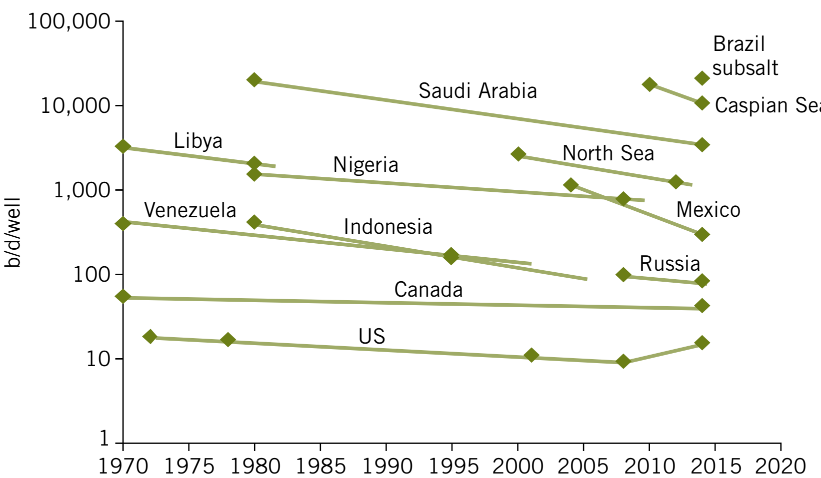
WELL-PRODUCTIVTIES OF MAJOR OIL PRODUCING FIELDS (cont'd)

Country, field year discovered	Formation	Age	Water depth, ft[1]	Reservoir depth, ft	Pore-pressure[2] gradient, psi/ft	Net thickness, ft	Lithology	Deposition
Brazil								
Marlim, 1985	Post-salt	Oligocene	3,543	11,520	0.53	240	Turbidite sands	Deep water
Lula, 2006	Pre-salt	Cretaceous	6,600	16,400	0.53	1,040	Turbidite sands	Deep water
North Sea								
Ekofisk, 1971	Ekofisk	Cretaceous	245	10,150	0.68	479	Chalk (limestone)	Marine pelagic
Forties, 1970	Forties	Paleocene	350	7,000	0.46	830	Turbidite sands	Deep water
Saudi Arabia								
Ghawar, 1948	Arab-D	Jurassic	—	6,400	0.45	200	Carbonate	Tidal
Safaniya, 1951	Safaniya	Cretaceous	50	5,100	0.45	136	Sandstone	Deltaic
Iraq								
Kirkuk, 1927	Baba	Oligocene	—	1,840	0.6	1,000	Carbonate	Shallow marine
Oman								
Yibal, 1963	Shaiba	Cretaceous	—	7,280	0.45	260	Carbonate	Shallow marine
Russia								
Samotlor, 1965	Megion	Jurassic	—	7,300	0.45	75	Sandstone	Deltaic
Chayvo, 1979	Nutovo	Miocene	—	7,400	0.44	490	Sandstone	Deltaic
Caspian								
ACG, 1958	Balakhany	Pliocene	380	11,600	0.5	150	Unconsolidated, sandstone	Deltaic
Karachaganak, 1979	Pre-salt	Permian	—	16,400	0.49	1,900	Carbonate	Shallow marine
China								
Daqing, 1959	Putaohua	Cretaceous	—	2,600	0.44	70	Unconsolidated , sandstone	Continental
Indonesia								
Minas, 1944	Sihapas	Miocene	—	2,340	0.42	438	Sandstone	Deltaic
Gialo, 1961	Chadra	Oligocene	—	2,200	0.44	400	Calcareous, sandstone	Shallow marine
Nigeria								
Bonga, 1996	Pre-salt	Miocene	3,300	8,640	0.44e	100	Turbidites	Deep water
Agbami, 1998	Pre-salt	Miocene	4,530	11,153	0.43e	470	Turbidites	Deep water
Angola								
Girassol, 1996	Pre-salt	Oligocene	4,600	4,800	0.43	360	Turbidites	Deep water
Kizomba A, 1998	Pre-salt	Miocene	3,850	6,290	0.44	400	Turbidites	Deep water

[1]Offshore fields show the water depth + reservoir depth from the sea bed. [2]A good approximation between reservoir pressure, P, and pore pressure gradient, Pg.: P = Pg * Depth. A normal Pg is ≤ 0.465 psi/ft; overpressure > 0.465. [3]*peak year

WELL PRODUCTIVITY

FIG. 1



at 16,500 b/d/well in 1981.

Agbami field offshore Nigeria highest well-productivity, 25,000 b/d/well, of the 16 offshore fields in the index. The average well-productivity for onshore fields is 2,260 b/d/well (excluding Ghawar) compared with 14,470 b/d/well for offshore.

The authors observed four types of reservoirs with regard to depositional environments:

- Deepwater turbidite sandstone (Brazil, West Africa, Gulf of Mexico, Permian basin, North Sea Forties).
- Deltaic sandstone (Venezuela, Russia).
- Shallow marine carbonate-lime-

Porosity, %	Permeability, md	Heterogeneity, net/gross pay	Gravity	Reservoir quality index	Production, b/d	Year³	Producing wells	Well-productivity, b/d/well	Field decline rate/year, %
20	>1,000	0.85	21	22	353,000	2007*	86	4,100	—
					204,000	2015	86	2,370	7
20	>1,000	0.75	29	83	120,000	2014	8	15,000	—
30	13	0.8	34	1	350,000	1976*	30	11,700	—
					110,000	2014	93	1,180	6
27	400	0.75	37	31	520,000	1980*	81	6,420	—
					41,000	2014	20	2,050	3
19	620	0.85	34	9	5,452,000	1981*	332	16,500	—
					5,000,000	2008	1,910	2,620	7
26	570	0.8	27	7	1,544,000	1981*	188	8,040	—
					500,000	2000	624	800	12
22	100	0.85	33	11	1,096,000	1971*	269	4,100	—
					900,000	2000	337	2,670	2
32	10	0.75	38	0.3	250,000	1997*	438	570	—
					100,000	2009	300	330	5
23	200	0.35	34	0.5	3,200,000	1980*	1,200	2,670	
					333,000	2009	13,400	25	16
22	247	0.60e	35	7	250,000	2007*	15	16,700	—
22	500	0.53	36	4	835,000	2010*	54	15,460	—
					684,000	2014	81	8,445	15
5	15	0.4	47	0.3	250,000	2014*	96	2,600	
30	>1,000	0.50	32	5	1,100,000	1976*	10,000e	110	—
					802,000	2014	20,784	38	3
27	> 1,000	0.70	34	35	416,000	1973*	530	785	
					188,000	1995	511	370	3
18	200	0.70	35	4	392,000	1970	126	3,100	—
					220,000	1980	242	900	12
37	> 1,000	0.85	29	14	202,000	2006*	10	20,200	—
					202,000	2009	13	15,540	9
35	> 1,000	0.8	45	57	250,000	2009*	10	25,000	—
					200,000	2014	21	9,520	19
35	>1,000	0.6	32	33	500,000	2008*	23	21,700	
35e	> 1,000	0.80e	35	49	250,000	2004*	13	19,230	

stone (Middle East, Mexico, Caspian).

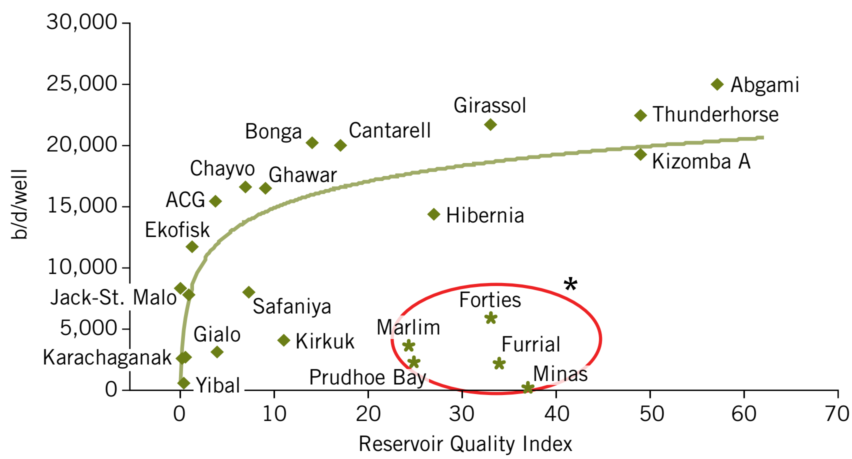
- Unconsolidated deltaic and continental sands (China, Canada, Caspian).

Environments differing from these four include the North Sea's Ekofisk Pelagic chalk reservoir, and Libya's Gialo field, a shallow marine calcareous sandstone reservoir.

Differences in depositional environments are the primary forces responsible for differences in reservoir parameters such as lithology, porosity, permeability, reservoir architecture (thickness, areal extent), and heterogeneities that refer to vertical and lateral changes over short distances.

PEAK WELL PRODUCTIVITY

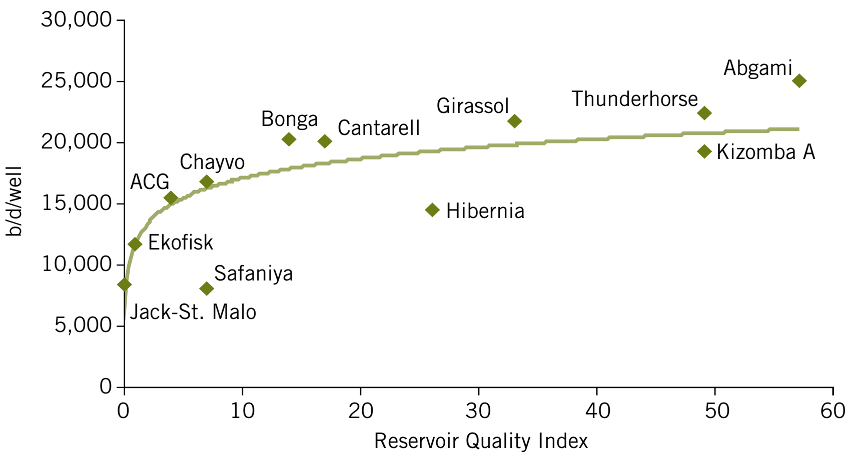
FIG. 2



*Five fields having low-peak well productivity excluded from the correlation.

PEAK WELL PRODUCTIVITY, OFFSHORE

FIG. 3



These parameters control reservoir quality to varying degrees as reflected in the various well productivities (Fig. 1).

The late wildcatter Michel T. Halbouty coined the term the "Habitat of Oil." He listed these factors as influencing a basin's productivity capabilities:

- Source rocks with abundant marine or terrestrial organic matter (kerogen), much needed for hydrocarbon generation.
- Migration pathways, typically fault zones.
- Traps and associated reservoirs.
- Seals or impermeable zones such as shale bordering the reservoirs.
- Timing of hydrocarbon expulsion from source rocks.

Deepwater turbidite sandstone reservoirs occur in nine offshore fields in this study. Turbidite sandstone consists primarily of clastic sediments deposited in marine continental slope channels and in deep marine basins forming basinal lobes. They feature thinly laminated, fine-grained sandstone, and shale interbeds (e.g. Bouma Sequence).

Turbidite sandstone tends to have complex architecture that governs thickness and lateral extent. Typical turbidite channels and lobes provide good porosity and permeability. The presence of abundant shale laminae hampers vertical permeability.

These reservoirs contain large reserves of mostly light oil and produce at high rates because they are associated with rich marine source rocks, consisting of thick stacked sandstone-shale intervals of large areal extent.

Thirteen fields in this study, including Ghawar, originated in a deltaic-tidal environment. Deltaic sandstone reservoirs consist of several facies capable of producing hydrocarbons at economic rates. These facies include distributary channels, overbank bay fill, crevasse splay, and distributary mouth-bar deposits.

Facies having the best reservoir quality are distributary channels and mouth bars. They tend to have high porosity, averaging 30%, and high permeability, averaging 500 md.

Such reservoirs tend to be highly heterogeneous, with lithology, porosity, and permeability sometimes changing drastically over short distances. This heterogeneity can combine with meandering architecture to create vertical wells that are good producers, mediocre producers, and dry holes all within a short distance.

Typical known limestone reservoirs, such as those in Mexico (Samaria), the Middle East (Kirkuk), and the Caspian region (Karachaganak), consist of very thick beds of large areal extent with many large cavities, including vugs and fractures.

Shallow marine carbonate-limestone reservoirs are abundant worldwide. Such reservoirs are termed tight because most have low porosities, averaging 10%, and permeability of less than 1 md.

They consist of shallow water reefal calcium carbonate components that grow to form thick, dense, massive limestone beds. Fractures contribute to permeability along with vugs and other cavities, the size of which control porosity. Vugs and fractures are partly responsible for large volumes of original oil-in-place (OOIP).

These naturally fractured reservoirs typically consist of fracture-controlled, low permeability dense rock. They require fracture stimulation to increase permeability and boost flow rates. This study combined unconsolidated deltaic and continental sand reservoirs containing some of the largest reserves worldwide.

Deltaic and continental depositional environments differ in many ways, primarily the source and components of their sediments. They are similar, however, in that their clastic components are uncemented, loose sand particles, typically with porosities averaging 35% and extremely high permeability.

Examples are Venezuela's Petrozuata, China's Daqing, Canada's Hibernia, and the Caspian's Azeri-Chirag-Gunashli fields. Petrozuata consists of thick (350 ft) fine-grained clean quartz sand at depths of 800-2,000 ft. These shallow reservoirs could be invaded by nearby freshwater, causing lighter oil migrated from deeper regions to be biodegraded into ultra-heavy oil of 8-10° gravity.

Reservoir quality index

A very limited sample size makes it difficult to correlate peak well-productivity with reservoir characteristics.

The authors grouped five measurements to create RQI, defined as the product of permeability (k, Darcy), net pay (h, ft), porosity (Ø, fraction), heterogeneity (N/G or net-to-gross sand ratio), and pore-pressure gradient (Pg, psi/ft of depth): RQI = k*h*Ø* N/G*Pg where the value of k*h has been shown to be a key factor in the flow potential of a well (OGJ, Dec. 17, 2001, p. 37).

A high RQI represents excellent reservoir characteristics that are apt to correspond to high well-productivity.

Reservoir engineers use RQI to forecast performance where h*Ø is a vital term in volumetric reserve calculations. Net/gross pay is an established parameter that defines reservoir heterogeneity, often critical to determining field size. Heterogeneity mitigates permeability and also influences volumetric reserves, the master determinant of production potential.

Pg reflects reservoir energy. Values greater than 0.465 psi/ft are overpressured. These reservoirs characteristically generate both high initial production/well and high field well-productivity.

Thunder Horse field is an example of an overpressured reservoir, with a Pg of 0.72 psi/ft and a very high well-productivity of 22,400 b/d/well. The highest RQI value for this set of fields is 83, Brazil's pre-salt Luna field.

Fig. 2 is a cross-plot of peak well-productivity and RQI. Although there is a high level of scatter, the plot exhibits a definitive log-linear relationship (r2 = 0.60), making the assumed indexing concept of reservoir quality appropriate.

The authors analyzed sensitivity of the five parameters pooled into the RQI definition by removing different parameters from the original set. For instance, runs were conducted with the index limited to three parameters: k*h*Ø, or just two, k*h, and so on. Results were definitive in that the complete set of five parameters generated by far the best correlation coefficient.

Fig. 2 also shows a cluster of five rogue fields grouped apart. The fields are Prudhoe Bay, Forties, Marlim, Furrial, and Minas. All have RQIs of 22-35. They also, and inexplicably, have relatively low peak well-productivities and were therefore excluded from the correlation.

Deepwater fields showed both very high RQIs and very high well-productivities (Fig. 3). Figs. 2-3 combined document a distinctive trend that supports the proposed RQI definition.

Ghawar has with the largest reserves (110 billion bbl) discovered in more than 100 years. Its RQI of 9 provides a guideline for the best fields. Other fields exist with higher RQI values and top reservoir quality but with reserves of less than 8 billion bbl.

The table includes a column with field-decline rates. Values range from 2%/year (Kirkuk) to 23%/year (Thunder Horse). High-decline rates are typical of overpressured reservoirs. Ghawar's field decline rate is 7%/year, well within the overall average. OGJ

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