San Joaquin, Permian basin oil production & reserves  
- Comments on Nehring’s 2006 paper on Hubbert’s unreliability

Richard Nehring in three bulletins of OJG of April 2006 criticized Hubbert’s forecasts of future oil production based on estimations of ultimates


Nehring wrote

_Hubbert based his analysis on deductions and extrapolations from two curves, one showing annual discoveries of oil, the other showing annual production of oil._

_Hubbert argued that both the annual discovery and the annual production curves were single-cycle curves; that is, each would have only one peak. Neither would be a multiple-cycle curve with two or more peaks substantially separated in time._

Moreover, he argued that both curves were horizontally symmetrical

_the cumulative discovery curve can be estimated by summing the cumulative production and proved reserves curves._

This statement is wrong when looking at the famous 1956 Hubbert’s paper: “Nuclear energy and fossil fuels” where he forecasted US (in fact USL48 because in 1956 Alaska was not yet part of the US) oil peak either for 1965 (ultimate 150 Gb) or 1970 (ultimate 200 Gb).

These USL48 ultimates of 150 Gb or 200 Gb by Hubbert are far from the cumulative production plus proved reserves being 82.4 Gb, sum which is wrongly considered by USGS and Nehring to represent ultimate. This confusion leads that Nehring’s criticism of unreliability of Hubbert is wrong on the examples of San Joaquin and Permian Basin, as we will see further

About only one cycle and symmetry, 1956 Hubbert displayed in figure 12 & 13 the oil production of Ohio and Illinois, explaining the reasons for several cycles.
Several peaks are more frequent than a single peak!
As shown in the next graph, the symmetry and one peak occurs for the USL48 oil production similar to a Gaussian curve (from 1900 to 2010) because in the US there are more than 20,000 oil producers who act in random, leading to a Gauss distribution. US oil producers act in random most of the times (Brownian motion) except if they are obliged by law to restrain their production (1950s) or by high price to produce at maximum (1980): these both constraints are shown by shoulder in the USL48 production.

In Illinois and Ohio there are few producers and the random motion does not work (as for Saudi Arabia with only one producer).

Hubbert’s 1956 forecast for the world coal was not symmetrical
Hubbert’s method is to draw a complete oil production curve starting from zero, going towards one peak (or two) and going down to zero at the end, where the main constraint is that the area beneath the curve equals the estimated ultimate.

Hubbert’s wrote page 9: *the production rate must begin at zero, and then after passing through one or several maxima, it must decline again to zero.*

Hubert was hand drawing the curve (no equation) and counting the area with squares! Nothing sophisticated showing that anyone could change the contour if keeping the surface below the curve!

His forecast for the US production of natural gas was also unsymmetrical.

On the US oil and gas future production, it is obvious as above that Hubbert was indicating the proven reserves but his ultimate added future discoveries to the proved reserves, as the probable reserves.

But Nehring wrote: *Hubbert also used a third curve, that of proved reserves over time. This curve is no longer necessary for the application of his method. Hubbert used it because the data sources available in the 1950s and early 1960s for measuring annual discoveries were poor. However, good historical data series did exist then for both annual production and annual proved reserves of crude oil.*
No, data of US proved reserves follows the SEC (Security and Exchange Commission) rules (to any company listed on the US market), being financial rules to protect the bankers and the shareholders against bad behaviors of US oil operators like JR Ewing in the Dallas series! In case of bankruptcy, the bankers want to recover their loans from the minimum value. Existing (EIA) production and proved reserves data are poor: US production data are not measures but estimates, and US proved reserves are wrong and should be deleted: the best proof is that, since 2010, California DOGGR does not report anymore reserves and that BOEM reports 2P (proved + probable) reserves for the GOM and not anymore 1P (proved) reserves. Furthermore it is scientifically incorrect to add proved field reserves to obtain the proved reserves of the country: this arithmetic aggregation leads to a large underestimation of the country (or basin) proved reserves and to reserves growth because this poor practice.

The incorrect arithmetic aggregation of proved reserves could be quickly explained in comparing to throwing one die: the probability of getting at least 2 (assumed to be the minimum) is 5 out of 6 or 82 %, when throwing two dice the probability of getting at least 4 (twice 2) is 33 out of 36 or 92 %; when throwing three dice the probability of getting at least 6 (three times 2) is 206 out of 216 or 95 %; when throwing 4 dice the probability of getting 8 (four times 2) is 1273 out of 1296 or 98%. Adding proves reserves leads to a strong underestimation. Ed Capen, an oil reserve expert, wrote in Feb 1996 SPE 11(1): "An industry that prides itself on its use of science, technology and frontier risk assessment finds itself in the 1990s with a reserve definition more reminiscent of the 1890s illegal addition of proved reserves" Laherrère J.H. 2008 «Advice from an old geologist-geophysicist on how to understand Nature» presentation Statoil Oslo 14 August

Nehring wrote rightly: The key to predicting production accurately using the Hubbert method is to have an accurate estimate of ultimate recovery

But in fact in the two examples where Nehring criticized Hubbert, he was using wrong ultimate estimates, confusing ultimate with the sum of cumulative production plus proved reserves, forgetting probable reserves and future discoveries!

-San Joaquin basin
Nehring stated: For the past century, it has been an important center of US oil production, being one of only eight major oil provinces in the country (a major province as used here is one with expected ultimate oil recovery of at least 8 billion bbl). Oil exploration and discovery in the San Joaquin Valley has a long history, going back to the late 19th century. The first discovery in the basin was the world-class giant Coalinga field in 1887 (610 million bbl cumulative production as of 1964). This was the first giant oil field discovered in any major US oil province. The other known giant fields in the basin as of 1964 were discovered in the next quarter century, beginning with Midway-Sunset in 1901 (1.1 billion bbl) and concluding with Buena Vista in 1909 (615 million bbl).
Nehring is wrongly calling EUR for Midway-Sunset an estimate of 1.1 Gb the sum of the cumulative production at end 1964 for Midway-Sunset 913 Mb and the proved reserves 199 Mb. The ultimate of the field is in fact cumulative production plus 2P reserves, but SEC forbids to report probable reserves (except to BOEM = USDOI/Bureau of Ocean Energy Management for the Gulf of Mexico fields, which has adopted the SPE/PRMS).

USGS in “Growth history of oil reserves on major California oil fields during the twentieth century” 2005 reported ultimate recovery for main fields in the San Joaquin Basin

http://pubs.usgs.gov/bul/b2172-h/b2172h508.pdf
The detail for Midway-Sunset is shown in this USGS graph: it is wrong to call ultimate an estimate which is growing with time and with the number of producing wells, because the poor practice of using only 1P reserves and not 2P.

It is not an ultimate but in fact cumulative production plus proved reserves (in blue), which increases as the number of wells (in brown). The Midway-Sunset cumulative production (in green) is extrapolated towards 3500 Mb, which is the value of the HL (Hubbert linearization of the crude oil production, as also the extrapolation of oil decline.
The oil remaining reserves display the current proved oil reserves as the backdated (EUR2015 = 3500 M) reserves as also 10 times the annual production.

In this graph, it is funny to find that the proved reserves is not far from ten times the annual production (because since 1920 the US R/P = proved reserves divided by annual production is close to 10 years: it was a US rule of thumb to quickly estimate reserves.

The USL48 R/P is plotted using the current proved reserves but also the backdated (at discovery time) of the field reserves estimated today (in fact updating USDOE/EIA-0534 1990 "US oil and gas reserves by year of field discovery" Aug. Open file).

If the current USL48 R/P stays around 10 years since 1920, the backdated R/P goes down from 80 years in 1932 (East Texas discovery) down to 15 years in 2010.
The EUR of Midway-Sunset (pages 6 & 11) was 850 Mb in 1923 and 3479 Mb in 2009. The EUR of Kern River (page 13) was 300 Mb in 1944 and 2630 Mb in 2009. Backdating field reserves is a must in order to get a good extrapolation of past discoveries (creaming curve).

Backdating is “the hour of truth”: see my graph 4 with Canada crude oil creaming curve from CAPP: Laherrère J.H. 2011 «Backdating is the key » ASPO 9 Brussels 27 April

CAPP (Canadian Association of Petroleum producers) data is precious because reporting directly the estimates from the operators and not through doubtful scouting.

This graph was saying that backdated Canada crude oil reserves is extrapolated towards an ultimate of 31 Gb when current discoveries goes towards the sky.
This truth was so painful that CAPP is not anymore reporting backdated discoveries as they did from 2006 to 2010 (at end 2009) at tables 2.21 a & b. CAPP does not want to show the truth!

It was the same for EIA which reports in 1990 in an open file USDOE/EIA-0534 1990 "US oil and gas reserves by year of field discovery" Aug; it was claimed to be the first of a series, but in fact it was the last and it is now unavailable!

EIA is afraid by the truth of backdating!

Nehring Associates is selling US field reserves: http://www.nehringdatabase.com/price_list.html

Nehring could very easily provide backdated oil reserves, but he does not want to show the truth!

It is well known that the proved remaining reserves are financial orientated for most oil operators (obliged to report only proved reserves from an audit to follow SEC rules of omitting to report probable reserves), when operators decide the development of their fields on 2P = proved + probable reserves) or political for OPEC members (reporting proved reserves without audit with the goal to obtain the maximum for quotas: from 1986 to 1989 300 Gb were added by OPEC members, being described in 2007 by Sadad al-Husseini (former Aramco VP) as speculative resources).

The graph of the world remaining oil reserves from different sources with the OPEC members without any audit and financial reserves for countries using SEC rules with audit) always on the rise since 1950 and the confidential backdated 2P reserves, peaking in 1980 and declining since.
Michael Jefferson (ESCP Europe Business School, former Shell Chief Econo


nist, former WEC) in a 2015 paper “The global energy assessment” http://onlinelibrary.wiley.com/doi/10.1002/wene.179/epdf stated that “the five major Middle East oil exporters altered the basis of their definition of ‘proved’ conventional oil reserves from a 90% probability down to a 50% probability from 1984”. He added “Put bluntly, the standard claim that the world has proved conventional oil reserves of nearly 1.7 trillion barrels is overstated by about 875 billion barrels”

In fact Jefferson said that the true remaining oil reserves in 2015 are 825 Gb, which about the value of my green curve. But I disagree that the five major Middle East oil reserves are 2P: they are unaudited and political. Roger Bentley Energy Institute, London - Oil Forecasting Workshop 4th & 5th November 2010 “Background Information” shows that the real 2P (Petroconsultants) oil reserves are less than the so called 1P oil reserves.

The problem is that scout companies recent 2P oil reserves have increased sharply between 2004 and 2011 to please their important ME clients, as I show in the graphs on Saudi Arabia cumulative oil discovery and production page 42 & 43 of my 2016 paper « World, US, Saudi Arabia, Russia & UK oil production & reserves -Comments on Rystad 2016 world reserves » August http://aspofrance.org/files/reservesUS_SA_%20Ru_UK-JL2016.pdf. The best proof that these ME oil reserves are political is that Neutral Zone (50/50 Saudi Arabia & Kuwait) oil reserves stayed constant when oil reserves climbed sharply in 1985 for Kuwait and in 1989 for Saudi Arabia.

The only problem is that BP oil reserves vary drastically with the year of the estimates for some countries as for Russia: Russian oil reserves were increasing for the 2014 edition (black) and decreasing for the 2015 (blue) & 2016 editions! Russian reserves are different from SPE rules.

BP reserves have changed also drastically for Australia, which is more difficult to explain!
The timing of reserves increase with bitumen in Canada varies with sources: 1999 for BP, 2003 for OGJ/EIA and 2009 for CAPP.

Athabasca tarsands production started in 1967 with a continuous growth: when to put the break: it seems to be in 1996.
It is well known that in recent years world discoveries are much less than the oil production (about 30 Gb/a), as reported by IHS.

BOEM is since 2010 reporting GOM oil reserves as 2P when in the past they were reporting only proved reserves, but BOEM is not obliged, as oil producers listed on the US stock market, to comply with the SEC rules.

Further the UK reserves example (Laherrere J.H. 2016 « World, US, Saudi Arabia, Russia & UK oil production & reserves-Comments on Rystad 2016 world reserves » August http://aspofrance.org/files/reservesUS_SA_%20Ru_UK-JL2016.pdf) shows that cumulative production plus proved reserves does not represent reliable ultimate as claimed by Nehring and USGS.

Midway-Sunset oil field, discovered in 1894, started production in 1900, peaked in 1914, 1937 and 1991 and declined after 1997. The sharp increase from 1960 to 1990 follows a sharp increase in...
number of wells and the start of fireflood (oil being heavy: 13-15°API) in 1960 and steamflood in 1963.

In my 2008 Oslo paper the oil decline (2000-2007) was leading towards 3600 Mb.

*Figure 19: Midway-Sunset (1894) oil decline as number of producing wells 1910-2007*

The HL of oil production trends (2000-2015) towards 3500 Gb

Nehring wrote further “Cumulative crude oil discoveries as of 1982 were 11.77 billion bbl, 52\% more than cumulative discoveries as of 1964.” with Midway-Sunset at 2.09 Gb and Kern River at 1.75 Gb: ultimate is now called cumulative discoveries, when in fact it is cumulative production plus proved reserves, always forgetting probable reserves to please the SEC.

CA DOGGR reports for 1982

<table>
<thead>
<tr>
<th></th>
<th>cumulative production</th>
<th>estimated reserves</th>
<th>CP+RR</th>
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<tbody>
<tr>
<td>Kern River</td>
<td>915</td>
<td>1031</td>
<td>1946</td>
</tr>
<tr>
<td>Midway-Sunset</td>
<td>1554</td>
<td>537</td>
<td>2091</td>
</tr>
</tbody>
</table>
OGJ Jan 31, 1983 reports for 1982
Kern River cumulative production estimated reserves CP+RR
Midway-Sunset 918 873 1791
1554 423 1977
Nehring reports DOGGR values for Midway-Sunset but wrongly for Kern River and he reports OGJ values for Kern River but wrongly for Midway-Sunset.

Kern River field discovered in 1899 is a heavy oil field like Midway-Sunset, which reached peak only in 1985

Kern oil decline (annual production versus cumulative production) can be extrapolated towards an ultimate of 2500 Gb for the period 1998-2007 and towards 3200 Gb for the period 2007-2015

Jean Laherrere June 2016
In my 2008 Oslo paper the figure 21 displayed an oil decline leading to a smaller ultimate

Figure 21: Kern River (1899 13°API) oil decline 1900-2007

The last DOGGR estimate CP+RR is at end 2009 cumulative production 2064 Mb and oil reserves 569 Mb with CP+RR = 2634 Mb
Kern River cumulative oil production plus reserves is plotted as the cumulative production plus 10 times annual production and the ultimates from HL and oil decline.

![Kern River cumulative production, ultimates as CP + 10 aP](image)

The current remaining oil proved reserves is compared to the backdated 2015 (EUR= 2450 Mb) and also to the annual production multiplied by 10: this rule of thumb is used at the beginning but contrary with Midway-Sunset it diverges from proved reserves because the field is operated by a major = Chevron, which is better in estimating reserves.

![Kern River remaining oil reserves](image)
It is obvious that the evolution of San Joaquin ultimates as shown by Nehring is a good example that these so called EUR (estimated ultimates recovery) are poor practice, which was not used by Hubbert for the USL48 in 1956 where his ultimates of 150 Gb or 200 Gb were twice the sum cumulative production plus proved reserves as shown above.

The cumulative production (CP) plus EIA proved reserves (RR) display a curve very close to cumulative production plus ten times annual production (rule of thumb R/P = 10 years), showing that using proved reserves is a poor practice.
SVJgeology provides the complete data for 26 fields and it is possible then to plot the backdated (at 2009) discovery quite far from the discoveries using current reserves as provided by EIA. These 26 fields represent about 95% of SJ reserves and production. But backdated CP+RR1P data is better that current CP+RR1P data showing that since 1940 little reserves were found but it is still short of the truth, which is backdated CP+RR2P.

The 26 fields used by SVJgeology are plotted using DOGGR cumulative production and estimated reserves backdated at end 2009, 2000 and 1982. Unfortunately DOGGR were reporting reserves only from 1977 to 2009. Stopping reporting reserves after 2009 was attributed to lack of budget but could be also by lack of reliability of the estimates. At the same time BOEM stopped reporting 1P SEC reserves for the GOM, moving to reporting 2P SPE reserves.
The reserves growth of these data adding cumulative production and proved reserves shows that it is a poor practice, far from a reliable ultimate.

OGL was publishing in their January bulletins the US annual proved reserves by field from 1960 to 1999, and the evolution of the cumulative discoveries of 20 main fields is drastic.

The extrapolation of the total discovered (CP+RR) for these 20 fields at end 1949 (5.6 Gb estimated in 1959 and 12.6 in 1998) can be extrapolated towards 18 Gb or more.
A better practice is to estimate ultimate from the oil decline or from the Hubbert linearization. The oil decline extrapolation for the period 1986-1995 is 20 Gb and for the period 2001-2014 is 19.5 Gb.

The HL extrapolation for the period 1985-1994 is 15.5 Gb and for the 1993-2014 is 18.5 Gb.
But the only best way is to estimate for each field the 2P reserves at end 2015, to plot a “creaming curve” (cumulative discoveries versus the number of fields for all the fields of San Joaquin). There almost no major discoveries after 1974 (Yowlumne 113 Mb). EIA reports few new discoveries since 1977 to 2014 (seven for a total of 20 Mb).

Using an ultimate of 19 Gb, San Joaquin oil production is forecasted up to 2080 close to exhaustion.

Our forecast for 2020 oil production is about 125 Mb, far from 2006 Nehring forecast of 100 Mb (18 Gb ultimate) or 60 Mb (2000 projections).
It is hard to find a synthesis of complete oil production by field. Nehring does not report the historical oil production of the above graph, showing at least five peaks. The site http://www.sjvgeology.org/oil/ provides good production data for 26 fields of the San Joaquin basin. The six major fields are plotted: Keen River, Midway-Sunset, Belridge South, Cymric, Elk Hills and Lost Hills, all found before 1911 and with a peak in 1985. Those six fields represent in 2014 88 Mb or 59% of the San Joaquin oil production of 150 Mb. This annual oil production has a mean peak in 1986 at 272 Mb with a further plateau around 1999 at 222 Mb.
Nehring and SJVGeology production data for the first year of 1900 seem short compared to Kern River production provided by DOGGR.

A better graph of SJ annual production showing the different types of oil for the period 1900-1970 from http://www.sjvgeology.com/oil/index.html

![San Joaquin Valley Annual Production graph](image)

-Monterey shale
San Joaquin main source rock is the Monterey shale, which may produces also.

*The Monterey Formation is an extensive Miocene oil-rich geological sedimentary formation in California, with outcrops of the formation in parts of the California Coast Ranges, Peninsular Ranges, and on some of California's off-shore islands. The formation is the major source-rock for 37 to 38 billion barrels of oil in conventional traps such as sandstones.[1] This is most of California's known oil resources.[2] The Monterey has been extensively investigated and mapped for petroleum potential, and is of major importance for understanding the complex geological history of California. Its rocks are mostly highly siliceous strata that vary greatly in composition, stratigraphy, and tectono-stratigraphic history.*

*The US Energy Information Administration (EIA) estimated in 2014 that the 1,750 square mile Monterey Formation could yield about 600 million barrels of oil, from tight oil contained in the formation, down sharply from their 2011 estimate of a potential 15.4 billion barrels. It means that EIA in 2014 reduces by 96% the 2011 EIA/INTEK estimate: it seems to be a record of reduction in three years!*


The Monterey Shale formation contains about two-thirds of the nation's shale oil reserves Federal energy authorities have slashed by 96% the estimated amount of recoverable oil buried in California's vast Monterey Shale deposits, deflating its potential as a national "black gold mine" of petroleum.
David Hughes Dec 2013 : “Drilling California A reality check on the Monterey shale”
http://www.postcarbon.org/publications/drilling-california/
This report evaluates the claim of a 2011 report released by the U.S. Energy Information
Administration and prepared by INTEK Inc. (EIA/INTEK) that tight oil production in the Monterey
Formation could ultimately yield 15.42 billion barrels of oil. Central to the EIA/INTEK report’s
assumptions are that:

a.) The potential for tight oil production in the Monterey is analogous to other tight oil plays like
the Bakken and Eagle Ford.

b.) The inferred tight oil production potential can be applied uniformly to the entire play, without
regard to the widely varied geological characteristics within the Monterey Formation.

The CA density of inactive and active wells drilled between 1977 and 2013 is concentrated on San
Joaquin main fields.
The production of the Monterey shale peaked in 1982 at 160,000 b/d and declined since at less than 40,000 b/d in 2013.

The production of the Monterey shale is mainly in San Joaquin and in particular Elk Hills field.
Hughes displays two cross sections through the main fields (Midway-Sunset) of SJV as the pods of active source-rock.
The initial productivity of all shale wells producing from the Monterey Formation in the San Joaquin Basin is illustrated in Figure 28 (this excludes production from the conventional Stevens Sand member of the Monterey).

The most recent data reveal that wells have been unable to produce anything close to the optimistic assumptions of the EIA/INTEK report.

It is also noteworthy that drilling has reverted to mainly vertical wells in the past five years.

Hughes concludes:

Geology
- The Monterey is not comparable to other tight oil plays. It is structurally and stratigraphically complex and thus is highly variable compared to plays such as the Bakken and Eagle Ford.
- Even within the Monterey’s limited areal extent, areas of uplifted mature source rocks with non-migrated oil are likely to be much smaller than assumed by the EIA/INTEK report.
- Production from the Monterey has to date been largely from areally restricted structural and stratigraphic traps charged with migrated oil.

Thus the EIA/INTEK report’s basic assumptions about the area potentially available for tight oil production are likely highly optimistic (the report assumes that 28,032 wells can be drilled over a 1,752 square mile area, for a density of 16 wells per square mile). The notion of widespread regions that can be drilled at densities of 16 wells per square mile, with oil production per well at multiples of current well productivity and cumulative production, is wishful thinking that grossly overestimates true oil recovery potential.

-Permian Basin


The volume of giants discoveries varies between table 1 and table 3

discoveries Gb | 1974 T1 | 1999 T3 | 2004 T1
---|---|---|---
>500 Mb | 14.7 | 24.0 | 20.2
200-500 Mb | 3.3 | 5.2 | 4.3
100-200 Mb | 2.0 | 3.5 | 2.7
50-100 Mb | 1.9 | 2.8 | 2.4
The graph of total discoveries (estimated in 1999) displays a flattening of discoveries since 1970 on table 3, when table 1 displays an increase between 1979 and 2004: it is a mess!

Nehring (OGJ April 2006) as for San Joaquin displayed in 2006 oil discoveries up to 1964, 1982 and 2000, confusing ultimates = EUR with cumulative production plus proved reserves
Nehring wrote in the OGJ last article:

As Hubbert clearly recognized, valid predictions of future production depend on valid estimates of ultimate recovery. For the two basins examined in the first two parts of this article, the San Joaquin and Permian basins, the Hubbert method clearly fails to predict future production accurately.

No Nehring is not using the Hubbert method in his forecast, relying on bad ultimates using cumulative production + proved reserves, moving from 20 to 40 Gb.

The Permian Basin is complex, gathering several basins in particular Midland and Delaware, and several plays, located in two States: Texas and New Mexico, as shown in these graphs:

http://library.corporate-ir.net/library/90/909/90959/items/308679/PXD_SpraberryInvestorMeeting2.pdf
Permian Basin Plays

Source: Occidental Petroleum

http://www.naturalgasintel.com/permianinfo
It is difficult on the web to find a synthesis of historical oil production from start to now. University of Texas has a site for the Permian basin = UTPB
The oil production started in 1924 has a peak in 1930, another one in 1973 at 756 Mb and since 2010 has increased sharply using horizontal drilling and fracking to recover both conventional and unconventional (LTO = light tight oil) oil.

Most of PB production comes from carbonate (Dutton et al BEG University of Texas 2004 http://www.beg.utexas.edu/resprog/permianbasin/pdfs/PA_FinlRpt.pdf)

Figure 130. Production histories of significant-sized oil reservoirs in the Permian Basin by lithology.
Carbonate production declines more than sandstone production!
The Hubbert linearization of this oil production can be extrapolated for the period 1972-1983 towards 30 Gb and for the period 1983-2007 towards 37 Gb. It is hard to make any extrapolating from 2015.

For the oil decline the period 1976-2007 can be extrapolated towards an ultimate of 42 Gb but from 2015 it is almost impossible and can be 45 or 50 Gb or else.

The oil production was forecasted using several ultimates from 40 to 50 Gb. It is interesting to notice that the decline after the peak of 1973 is symmetrical with the increase 1960-1973, as it was for the peak of 1930 and it is likely that the decline after the peak of 2015 will be also symmetrical as it is for an ultimate of around 45 Gb.
An oil ultimate of 40 Gb (higher than Nehring) is lower than the estimate from the extrapolation of oil decline (for 1976-2007) and seems unlikely.

An ultimate of 45 and 50 Gb is more likely and the forecast for 2020 is 580-600 Mb.

Nehring in 2006 failed to forecast the sharp oil increase since 2008, his last estimate for ultimate being 40 Gb is 230 Mb for 2020, very far from the above forecast being between 580 and 600 Mb.
The Permian Basin being complex, the production data vary between sources. Rystad PB oil production value for 1960 is lower than the production value for Yates.

The two main fields are Wasson found in 1936 and Yates in 1926. The extrapolation of the oil decline goes towards an ultimate of 3400 Mb for Wasson and 1600 Mb for Yates.

Wasson oil decline is extrapolated from 1949-1961 towards 450 Mb, from 1973 to 1988 towards 1800 Mb, but from 1989 to 2014 towards 2800 Mb.
Wasson cumulative production is extrapolated with three cycles corresponding with the above HL.

In my 2008 Oslo paper the forecast of production by Kinder Morgan up to 2015 was right. Figure 25: Yates oil production

Yates oil decline can be extrapolated differently with time: 1985-1992 towards 1350 Mb, 1998-2002 towards 1450 Mb, 2009-2015 towards 1650 Mb. Ultimate was reported by OGJ 1977-1998 at 1950 Mb. USGS 2012 reports Yates ultimate at 1935 Mb: it is unlikely that this ultimate will be reached looking at the oil decline in 2015.
In my 2008 Oslo paper Yates was stated likely an example of negative reserve growth when looking at 1979 Nehring or OGJ reserve estimate.
Nehring reports the crude EUR estimated in 1979 and 2004 with Wasson increase and Yates decrease.

In the LTO from EIA the Permian Basin is a major item with Spraberry, Bonespring, Wolfcamp, Delaware and Yeso-Glorieta

https://www.eia.gov/pressroom/presentations/sieminski_01262016_mx.pdf
RRC in http://www.rrc.state.tx.us/media/1471/top_5_yearly_graph_1_of_2.pdf displays from 1993 to 2012 the large increase of Spraberry production compared to other fields as Wasson; Yates, Slaugher and Levelland.

![Yearly Production for Top 10 Current Largest Permian Basin Fields](image)


Spraberry oil production increased since 2007 with a large increase with the number of production wells from 10 000 wells to 25 000 wells. Most of the increase from 2010 to 2013 comes from vertical wells, but since 2013 from horizontal wells.

Spraberry (trend area) started to produce in 1954 (Pioneer graph) http://library.corporate.ir.net/library/90/909/90959/items/308679/PXD_SpraberryInvestorMeeting2.pdf
Wikipedia https://en.wikipedia.org/wiki/Spraberry_Trend writes that the Spraberry trend discovered in 1943 was dubbed in the 50s as “the world’s largest unrecoverable oil reserve” and in 2007 reported reserves by EIA were 10 Gb.

David Hughes in 2015 http://www.postcarbon.org/wp-content/uploads/2015/09/Hughes_Tight-Oil-Reality-Check.pdf forecasted the Spraberry trend to peak around 2020 about 0.5 Mb/d. AEO 2015 lowers AEO 2014 Spraberry reserves by 28% down to 4.4 Gb, meaning that there are problems in estimating LTO reserves, in particular when there are in part conventional reserves!

2.4 Spraberry Play

Figure 6 illustrates the AEO2015 reference case forecast for the Spraberry compared to AEO2014. In AEO2015, the Spraberry, which is one of the largest plays in the Permian Basin, is forecast to produce 9.3% of all tight oil production from 2014 to 2040.

Figure 7. Spraberry Play actual production through 2014 compared to the EIA’s AEO2014 and AEO2015 forecasts. The EIA has reduced its very optimistic forecast of cumulative 2014-2040 recovery by 28% in AEO2015.
estimates Spraberry/Wolfcamp reserves (Gboe) at 50 Gboe between Ghawar and Burgan: wishful thinking!

The Permian Basin is the basin with the most EOR and CO2 projects in the US (over 50%)
http://www.ogj.com/articles/print/volume-112/issue-4/special-report-eor-heavy-oil-survey/co-sub-2-sub-eor-set-for-
growth-as-new-co-sub-2-sub-supplies-emerge.html

EOR is confused by most as being LTO, LTO is EOR but not all EOR is LTO

Horizontal drilling started in fact in 2010
http://www.energyeconomist.com/a6257783p/exploration/detail/permian/graph/oilvdh.gif
Permian Basin oil production is peaking in 2016

The addition of these 4 graphs gives for the PB the difference between 2006 and 2015 is 2006-2015 Vertical Horizontal
wells k 12 9
production kb/d 280 880
Horizontal wells produce four times more than vertical wells

Where are the present sweet spots?
Rystad http://www.rystadenergy.com/NewsEvents/Newsletters/UsArchive/shale-newsletter-may-2016 reports the breakeven oil price for wells drilled in 2015 the sweet spots are the blue dots

Figure 2: Permian wellhead breakeven oil prices for wells spudded in 2015– USD/bbl

![Permian Basin Wellhead Breakeven Oil Price](image)

Source: Rystad Energy NASWellCube (Premium)

Baker Hughes rig map for the Permian Basin shows the present drilling in August 2016, most being on the sweet spots.

![Baker Hughes rig map](image)

With the oil price decline many LTO drilled wells were not completed: called DUC = drilled uncompleted and their number increased drastically since mid 2015, in particular for the Permian Basin
But the DUC data is not reliable when comparing Rystad and Blomberg graphs.

Rystad July 2016 assumes that drilling activity will resume in the Permian Basin with oil price above 50 $/b: it is in line with EIA/AEO 2016.
EIA/AEO 2016 forecasts LTO reaching a low on 2017 after a peak in 2015

Rystad and EIA base their forecast on number of wells drilled and its economy but fail to ask if there is enough room for all these wells: sweet spots seem already almost depleted: see my paper Laherrere J.H. 2016 « World, US, Saudi Arabia, Russia & UK oil production & reserves-Comments on Rystad 2016 world reserves » August

Most of the so called LTO for the Permian Basin comes from conventional fields which are not produced with horizontal drilling and hydraulic fracturation to improve their production as it was done in the 90s by Shell with two giants fields (largest in their countries: Yibal in Oman and Rabi-Kounga in Gabon)

My 2008 Oslo paper displayed
Same sharp decline as Yibal after large use of horizontal wells again by Shell with Rabi-Kounga (largest oilfield in Gabon) leading to high production peak, but a decrease in oil reserves
Figure 56: Rabi-Kounga oil decline 1989-2006
Figure 57: Rabi-Kounga oil production
IFP panorama 2005 quoted Rabi-Kounga as an example of the impact of horizontal drilling to increase recovery factor from 31% (1986) to 55% (2004), going from 905 Mb in 1993 to 1005 Mb (what an accuracy!) in 2004, when IHS reports in 2008 865 Mb
Figure 58: Rabi-Kounga oil production from IFP Panorama 2005

Figure 59: Rabi-Kounga oil ultimates & cumulative production
The 2016 updated graph shows that since the peak in 1997 down to 2015 Rabi-Kounga production has declined by 15% per year.

The oil decline for 2004-2015 trends towards 900 Mb ultimate, which was the estimate in 2008, but much lower than the estimate in 1995, after horizontal drilling, before the oil peak of 1997!
-Conclusion
Nehring was wrong to call Hubbert forecasts unreliable because using Hubbert curves based on ultimates (EUR) being the cumulative production plus proved reserves for two basins at different years: 1964, 1982 & 2000 for San Joaquin (8.7, 11.9 & 16.1 Gb) & Permian Basin (27.5, 30.5 & 37.5 Gb).
Hubbert was not using such data as in his 1956 famous forecast of US oil peak in 1970 based on an ultimate of 200 Gb, quite far from the cumulative production (at end 1955 = 52 Gb) plus proved reserves (at end 1955 = 30 Gb) being 82 Gb.
Extrapolating past production up to 2015, the ultimates are 19 Gb for SJ and 40-50 Gb for PB, much higher than the so-called EUR by Nehring.
The poor practice of US proved reserves imposed by the SEC to every oil company listed on the US stock market (but not to BOEM, which decided in 2010 to report the right reserves being 2P = proved plus probable).
Nehring was wrong in 2006 to describe Hubbert’s unreliability.
He should have described SEC proved reserves unreliability and he should have added that the arithmetic addition of field oil proved reserves does not equal the proved reserves of the country (or of the world), being a wide underestimation leading to a reserve growth! Only arithmetic aggregation of 2P reserves is correct.
But SEC rules are the law for the oil companies listed on the US stock market: the rules have to be changed by adding probable reserves to proved reserves, but the rules will be changed only if experts as Nehring say so!
But the truth (to day backdated remaining reserves) is hard to show.
Only BOEM has the courage since 2009 to use 2P reserves for the GOM (but not for the Pacific!).
In contrary CA DOGGR does not anymore report field oil proved reserves since 2009 after 32 years of doing so!