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Communication

Comment on the 'Uppsala critique' ☆

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HIGHLIGHTS

- We examine the criticisms made by Aleklett et al. of the IEA oil production outlook.
- The authors incorrectly compare depletion rates from regions and groups of fields.
- The reductions to future oil production the authors consider necessary are not valid.

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ABSTRACT

This paper discusses the criticisms of the IEA World Energy Outlook raised by Aleklett et al. (2010), often referred to as the 'Uppsala critique'. The major argument of Aleklett et al. is that the rates of depletion, the ratio of annual production to remaining resources or reserves, assumed by the IEA in certain categories of fields are unreasonable. In this paper, we call into question the reductions in future global oil production that Aleklett et al. argue are necessary: they have incorrectly applied a depletion rate for all fields within a region to different subsets of fields within a region. The more minor reductions to future global oil production that Aleklett et al. argue are needed because of the IEA modelling of the production of bitumen and natural gas liquids are also examined briefly.

1. Introduction

Aleklett et al. (2010) analysed the central oil production projection generated by the International Energy Agency (IEA, 2008) in its 2008 World Energy Outlook (WEO). Aleklett et al. consider that the IEA's outlook is unduly optimistic for four principle reasons, in that it

1. included an optimistic increase in production from discovered but undeveloped fields;
2. included an optimistic increase in production from undiscovered fields;
3. included optimistic assumptions for natural bitumen recovered by in situ technologies up to 2030; and
4. included an increase in future production of natural gas liquids (NGLs) which is not matched by a commensurate increase in natural gas production, with production of NGLs expressed in volumetric and not energetic terms.

This has subsequently been referred to as the 'Uppsala critique' (by e.g. Miller, 2011), and it continues to be used to criticise the outlooks produced by the IEA (see e.g. Chapman, 2014). This short comment piece thus seeks to investigate the validity of these criticisms.

2. Background to depletion rates

Aleklett et al. (2010) estimate that the first two of the points above alone warrant a reduction of 19.4 million barrels per day (mb/d) in production by 2030 from the levels suggested by the IEA in its 2008 WEO (106.4 mb/d).[1] The reasoning behind both of these points is the IEA's use of what Aleklett et al. consider to be unrealistically high 'depletion rates'.

The depletion rate in its most general sense is the ratio of annual production to some proportion of the resource base within a field, country, or region. The resource can be a variety of different

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[1] These production figures include all sources of conventional and unconventional oil, NGLs, processing gains, and unconventional liquids (such as coal-to-liquids and gas-to-liquids), but exclude biofuels. Aleklett et al. (2010) quote the 2030 production level generated by the IEA as 101.5 mb/d. The difference from the level actually given by the IEA (106.4 mb/d) results from their modification of reporting NGL production on an energy-equivalent basis (i.e. in million barrels of oil equivalent) rather than as a volume. This is discussed in more detail below.

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estimates: the *ultimately recoverable resource* (URR), the *remaining ultimately recoverable resources* (RURR), or existing reserves. The RURR is the difference between the URR and cumulative production up to any given date. By the normal definitions RURR estimates consist of the sum of remaining reserves (see below), potential future reserve growth, and undiscovered resources (see e.g. Sorrell et al., 2010).

If the URR is used on the denominator of the depletion rate, then the denominator is essentially fixed.[2] If the RURR is placed on the denominator, then as annual production proceeds, this denominator will change as cumulative production is subtracted from the remaining resources.

It has been well established that annual production from most oil fields rises to a maximum, reaches a peak or plateau, and then declines (Höök et al., 2009). Over these stages of a field's life, the depletion rate tends to increase prior to the peak in production and reach a maximum value at the peak. If it is assumed that the subsequent decline in production from that field will be exponential (a common assumption, but one which is not always correct (Sorrell and Speirs, 2010)), then the rate of depletion remains constant at exactly the assumed decline rate.

The behaviour of regional depletion rates is slightly different, as there are additional volumes of oil that can be included within the URR or RURR of the region from which no production has occurred. For example, there may be large volumes of undiscovered oil estimated to exist within a region. These volumes would be included in the regional URR or RURR, but would not have contributed to total annual production from that region. Consequently, it is important to recognise that the depletion rate for a region ought to be less than the weighted sum of the depletion rates of the producing fields within that region.

Another example of an important potential addition to the URR or RURR of a region is the volume of oil held in fields that have been discovered but not developed. When there are also no existing plans for them to be developed, these are sometimes called 'Potential Additional Resources' (by DECC, 2013), or alternatively 'fallow fields'. Although the volumes in these fields are often small, they can have an important impact on a calculated depletion rate, especially in a mature country or region.[3] A much more detailed discussion of the dynamics of depletion rates is provided by Höök et al. (2009).

As noted above, the denominator can also be taken to be remaining reserves, in which case the depletion rate is simply the inverse of the commonly quoted R/P ratio. However, a number of different *reserve* estimates could be used. Reserves are a subset of the ultimately recoverable resources, and are those volumes of oil that are currently technically and economically producible and which have a defined probability of being produced. The various reserve definitions that could be used have been well documented (see e.g. McGlade and Ekins, 2014; McGlade, 2012; Sorrell et al., 2009), but of most importance is the difference between 'proved' (1P), 'proved and probable' (2P), and 'proved, probable and possible' (3P) estimates. Broadly speaking 1P estimates are the most conservative, and most frequently used in the R/P ratio, while 2P estimates are the median estimate of the reserves for a given field, country or region. Since 1P estimates are more conservative than 2P estimates, a depletion rate using 1P reserves on the denominator will tend to be larger than the one using 2P. This applies whether the denominator of the depletion rate ratio is solely reserves, or an estimate of the URR of which reserves are a subset.

3. Depletion rates calculated by Aleklett et al.

Aleklett et al. (2010) use the RURR in their depletion rates i.e. annual production on the nominator and URR minus cumulative production up to that year on the denominator. They first estimate depletion rates in different regions over extended time periods, relying on historical production and their own estimates of the URR in each. In the North Sea for example, they estimate that the URR was initially 75 Gb, and had a depletion rate that rose at around 0.2–0.3%/year from 1975 to 2000 and plateaued at around 6%. Of the regions analysed, they calculate that the depletion rate in the UK has plateaued at the highest level (around 6.9%) and has been around 2–3% for Middle Eastern countries.

It is unclear whether Aleklett et al. (2010) have used 1P, 2P or 3P reserve estimates in their URR estimates. In the following discussion, it is assumed that Aleklett et al., when they compare depletion rates for different categories of fields and regions, have relied on consistent reserve definitions; if they have not done so, then this is a fundamental error that would undermine their conclusions. Aleklett et al. (2010) also do not make it clear to what extent undiscovered oil and reserve growth have been included in their regional URR estimates.

Aleklett et al. (2010) next look at the depletion rates that are implicitly assumed by the IEA for two categories of fields in its 2008 WEO. These two categories are undiscovered fields and 'discovered but undeveloped fields'. The latter of these categories is further disaggregated into four groups: undeveloped onshore OPEC fields, undeveloped offshore OPEC fields, undeveloped non-OPEC onshore fields, and undeveloped non-OPEC offshore fields. The estimates of the RURR that Aleklett et al. use on the denominator of the depletion rates for these four groups and for the undiscovered category (which they investigate on a global level only) rely upon resource estimates provided by the IEA. Aleklett et al. estimate the implied depletion rate by dividing the IEA's projection of annual production from each category of field by the remaining ultimately recoverable resources at those fields (i.e. the URR minus cumulative production). They conclude that the IEA has assumed depletion rates that rise well above 12% in three of the four groups of discovered but undeveloped fields and rise to just below 10% for the category of undiscovered fields.

The IEA indicates that the resource estimates for all four of the more disaggregated groups within the category of discovered but undeveloped fields rely upon data from the consultancy IHS CERA. Data from IHS CERA is for 2P reserve estimates (as stated explicitly by the IEA, 2008), and so the URR estimates used in the depletion rate calculations by Aleklett et al. (2010) for these four groups contain only 2P reserves. The resource estimates do not appear to include any potential volumes coming from the technical drivers of reserve growth, such as the potential use of enhanced oil recovery (although this is unclear), and they have been selected so that the URR has an undiscovered resource component equal to zero (as the groups strictly contain only fields that have already been discovered).

For the URR used in the undiscovered category, Aleklett et al. (2010) have taken the volume that the IEA (2008) indicates is '*the projected discovery of 114 billion barrels of reserves worldwide over the projection period*'. In other words, the URR estimate used by Aleklett et al. is the total volume of oil projected to be discovered globally between the end of 2007 and 2030. It is unclear what definition of 'reserves' is being used for this estimate of 114 Gb, and it is also unclear whether it includes any volumes of reserve

[2] The URR should, strictly speaking, be defined and estimated so that it is a fixed value (McGlade, 2012). However, historic estimates of the global URR have tended to change over time (see e.g. Ahlbrandt, 2006); this discussion is not relevant to the arguments set out in this paper.

[3] These 'Potential Additional Resources' do not have a 'reasonable timetable for development' (or similar) (SPE, 2008) that is required for them to be classified as reserves. Equally they are not undiscovered, and so we classify them here as reserve growth. Reserve growth has multiple drivers, but in this paper it is important to clarify that it can come from: volumes in fallow fields, the use of advanced technologies such as enhanced oil recovery, changes in geological understanding, as well as from numerous definitional changes (see McGlade, 2012 for a more detailed discussion).

growth from factors such as enhanced oil recovery since this is not explicitly mentioned. It can, however, be assumed that both reserves are discovered but undeveloped volumes of oil are not included (or equivalently are included, but are equal to zero).

Aleklett et al. (2010) argue that since the depletion rates assumed by the IEA in these categories of fields are much larger than the rates previously observed in the regions, lower depletion rates should actually be applied. For the four groups of undeveloped fields, they lower the depletion rates from the levels suggested from 2010 onwards. These eventually reach much lower maximum levels of between 2% and 7% between 2020 and 2025. For undiscovered fields, they suggest that depletion rates should be lowered from 2019 onwards and should reach a maximum of around 3.5% in 2030. By assuming lower depletion rates for these categories of fields, Aleklett et al. argue that production cannot rise nearly as quickly as indicated by the IEA throughout the projection period. These reductions lead to their claim that global production of all oil in 2030 should be lowered by 19.4 mb/d.

This argument may be somewhat flawed however. For both categories of fields, Aleklett et al. have compared the depletion rate from a whole region (e.g. the North Sea) with that for a selected subset of fields within a region (e.g. undeveloped, onshore OPEC fields). This is not comparing like-with-like.

As discussed above, the depletion rate Aleklett et al. estimated for the North Sea (for example) assumes that the denominator of the depletion rate on a given date should be the RURR: URR minus cumulative production up to that date. The URR for the North Sea will contain volumes from fields that are classified as reserves, volumes estimated to be undiscovered, and volumes from anticipated future reserve growth.

Looking first at the four groups of discovered but undeveloped fields, as mentioned above, there is ambiguity over whether any reserve growth has been included in the IEA resource estimate. However, it is clear that no undiscovered resources are included. For the regions on the other hand, the URR estimates contain undiscovered volumes. Production obviously cannot have occurred from these fields historically, and so the depletion rate for the region contains fields whose resources are included in the denominator, but from which there is no production (on the nominator). For the category of discovered but undeveloped fields, no resources from which there is no production are included, because any such resources have been specifically excluded from the denominator. In other words, estimates of the URR of discovered but undeveloped fields within a region are necessarily lower than estimates of the URR of the region as a whole, since the latter includes the resources of undiscovered fields. It is therefore unsurprising that the depletion rate calculated for the IEA category of fields is larger than the depletion rate for the region.

A slightly different argument explains why Aleklett et al. calculate a significantly larger depletion rate for the undiscovered category of fields than for any of the regions. It is worth restating that the resource estimate Aleklett et al. used for the denominator of depletion rate for the undiscovered category included only volumes that were discovered between 2007 and 2030. This is not a true estimate of the total undiscovered resources of all undiscovered fields: Aleklett et al. have excluded any resources from fields that could be discovered after 2030.

Estimates of the remaining volumes of global undiscovered oil vary significantly (see e.g. McGlade, forthcoming; Sorrell et al., 2009). However, of the publically available estimates, the lowest is given by Campbell (2013), who estimates that total volumes discovered from 2010 onwards will be 113 Gb. Many sources lie approximately in the range 200–350 Gb (see e.g. the various studies reported by Bentley et al., 2009), while the latest global assessment by the United States Geological Survey is around 825 Gb (including NGL) (Brownfield et al., 2012; EIA, 2011; USGS, 2011). Campbell (2013) uses a very narrow definition of oil,[4] which likely underestimates all oil that can be discovered over the rest of time. The figure of 114 Gb used by Aleklett et al. (2010) is therefore not a true URR of all undiscovered fields (as of 2007) globally.

Aleklett et al. (2010) have therefore excluded the resources of fields that cannot contribute to production over the projected time period when examining the IEA category of fields, but included the resources of fields that have not contributed to production over the historical period when examining the regions. This difference means that the depletion rate for the category of fields will be larger than the depletion rates for the regions.

It is worth explicitly drawing a distinction between the IEA category of undiscovered fields and a single basin prior to its first oil discovery, e.g. the UK North Sea in the mid-1960s. An analogy *could* be drawn between the depletion rates of the IEA category and the UK North Sea, but only if one was to construct a URR for the UK North Sea that included volumes of oil that were produced, discovered, or classified as reserves within a well-defined time period (say between 1965 and 1995), and excluded the resources that could be discovered after this time.

For reserve growth, as mentioned above, it is ambiguous whether volumes from factors such as enhanced oil recovery have been included in the URR estimates for the two IEA categories of fields (although it appears unlikely). However, it is evident that volumes from fallow fields, another driver of reserve growth, are likely included in the regional estimates of URR but not in the IEA category of undiscovered fields. This discrepancy means that the depletion rates calculated for the undiscovered category appear to be more different than they would do if consistent URRs were to be used for both.

In summary, when calculating the depletion rates for the IEA category of undeveloped fields, Aleklett et al. (2010) have used spatially restrictive URRs, which only contain volumes of reserves, and compared this to spatially more inclusive URRs (for the regions), which also include estimates of resources in undiscovered fields. For the IEA category of undiscovered fields, Aleklett et al. have used a temporally restrictive URR, which only contains volumes from fields discovered within a certain timeframe, and compared this to temporally more inclusive URRs (for the regions), which also include estimates of resources in fields that could be produced over all time. In the latter case, Aleklett et al. have also included volumes from fallow fields in the regional URRs but excluded these from the category of fields.

The exclusion of certain elements of the URR from the denominator can have a major effect on the estimated depletion rate. This is illustrated in Fig. 1. Taking the latest data from the UK Department of Energy and Climate Change (DECC, 2013) on UK resources, and data from BP (2013) for historical UK production, the UK's URR is estimated to be around 42.4 Gb. This comprises 6.1 Gb of current 2P reserves, 2.1 Gb in discovered but undeveloped fields, 1.9 Gb of possible reserves (both of these two volumes have the potential to contribute via reserve growth), and 5.8 Gb of undiscovered oil, and 26.5 Gb of cumulative production that has occurred since the beginning of development of the UK North Sea. With the RURR on the denominator (i.e. 42.4 Gb minus cumulative production up to the date in question), the depletion rate reaches a maximum of around 4.5%. If undiscovered and reserve growth resources are excluded from the denominator (i.e. 32.6 Gb minus cumulative production up to the date in question),[5] this maximum rate almost doubles to 8.5%. This demonstrates that excluding certain

[4] Campbell (2013) analyses ‘Regular conventional oil’, which includes all oil identified above as conventional oil except for: crude oil $<17.5°$API, oil found at water depths greater than 500 m, Arctic oil, and NGL from gas plants.

[5] This has been calculated using $42.4-2.1-1.9-5.8=32.6$ Gb.

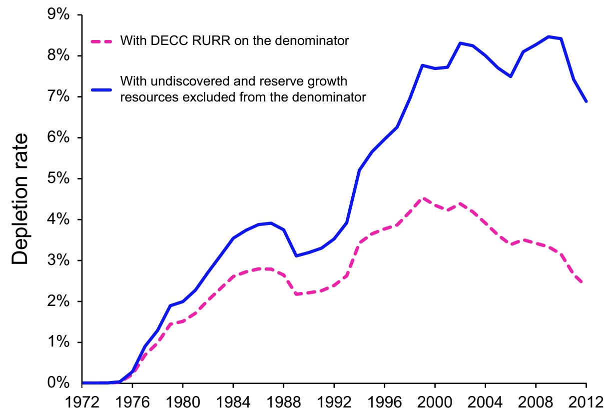

Fig. 1. Historical depletion rates for the UK with different depletion rate denominators.

categories of oil (in this case reserve growth and undiscovered oil) can significantly alter the calculated depletion rate for a region.

There are two options to provide a more appropriate critique of the IEA production projections using depletion rates. First, one could compare depletion rates assumed from *all* fields in a given IEA region. In this region, the denominator of the depletion rate should include resources from the sum of current reserves, undiscovered fields and reserve growth, and the numerator the production from all of these fields. For example, one could compare the total depletion rate for all onshore OPEC fields (not just discovered and undeveloped fields) with the historical depletion rates that Aleklett et al. (2010) derive for the various other regions examined.

Second, one could calculate historical depletion rates for a selected group of fields from a region e.g. fields that were at one point considered undiscovered but that have subsequently been discovered and brought into production within a certain timeframe. This rate could then be compared directly with the depletion rates that the IEA uses (as calculated by the Uppsala group) for the groups of fields in the various categories mentioned above. One example of this has been carried out in Fig. 1 for the depletion rate with the initial URR that includes only cumulative production and current 2P reserves on the denominator (and thus excludes reserve growth and undiscovered fields). This is a temporally restrictive depletion rate, which includes only the production from, and resources of, fields that have produced any volumes of oil or are currently classified as reserves. This is more equivalent to the IEA category of undiscovered fields that includes only the production from, and resources of, fields that are discovered within the IEA model timeframe. The difference between these calculated depletion rates is around 1%.

In conclusion, without performing analysis along these lines, it is difficult for Aleklett et al. (2010) to argue that the imposed reduction in depletion rates, and hence overall production rates, is justified, or that the IEA has been optimistic in its assumptions.

4. Production of bitumen and natural gas liquids

The remaining two points in the above list are somewhat different. Concerning the third of these points, the IEA suggested in situ bitumen recovery production would reach 4.5 mb/d by 2030, a figure Aleklett et al. (2010) considered was 2.3 mb/d too high. Projections from both the CAPP (2013) and the NEB (2011) suggest that there is certainly the *potential* for in situ recovery to increase to the levels suggested by the IEA (these two organisations suggest rises to 5.2 mb/d and 4.7 mb/d in 2030). The salient point is therefore whether there will be sufficient investment in these projects to bring this production on line; whether the IEA estimate is too high or not remains a matter of opinion unless this is modelled in a detailed manner, which Aleklett et al. did not do.

Regarding the fourth and final of the above points, an important issue is raised regarding the inconsistent increases in production of NGLs and natural gas. As noted by Aleklett et al. (2010), the IEA (2008) stated that *'the average NGL content of gas production is constant over the projection period'*, and so there was a disconnect between the estimated rise in NGL production and gas production.

The IEA appears to have changed its stance on this issue, however. It has subsequently indicated that natural gas production will shift to wetter sources, for example by increased gas production in the Middle East which has a higher NGL content (IEA, 2012). In the 2008 WEO, the IEA estimated that NGL production (in volumetric terms) would rise to 19.8 mb/d by 2030, while in the latest 2012 WEO, it suggests a figure of around 16 mb/d in 2030. This latter number is not dissimilar to the level that Aleklett et al. (2010) indicate is a reasonable level (15.5 mb/d (again in volumetric terms)). It thus appears that this criticism raised by Aleklett et al. was justified at the time of publication.

On the second criticism of the IEA's handling of NGLs, that NGLs should be reported in terms of energy rather than volume, it should be noted that while NGLs undoubtedly do have a lower energy density than (most) crude oils, NGLs have a wide variety of uses, and do substitute for oil in a number of sectors. For example in the United States, as reported by Troner (2013), 55% of NGLs are used in the petrochemical industries, 20% used as a gasoline blendstock, 20% used for space heating or fuel, and the remainder exported. Whether NGLs should be reported in terms of energy or volume clearly depends on whether it is the energy or volume of the feedstock used that is important. In the petrochemical industries, for example, the volume is the important metric, not the energetic content. If a barrel of NGLs displaces a barrel of crude oil needed for the same process, then measuring NGLs in volumetric terms appears to be reasonable. If NGLs are used for an alternative purpose, in which a given energy is required, for heat for example, then reporting NGLs as energy would be more useful.

5. Concluding remarks

The IEA produced an outlook for global oil production in 2008. Aleklett et al. (2010) raised a number of concerns about this projection, and their paper has since been cited frequently to call into question the 2008 and subsequent projections. However, a closer reading reveals that these concerns are not well founded. They have incorrectly applied a depletion rate for all fields within a region to different subsets of fields within a region: this is not a like-with-like comparison. It is also argued that bitumen production levels are optimistic, but this is not supported by any detailed modelling, and so the revision suggested by Aleklett et al. is a matter of opinion. The final point, concerning the incommensurate rise of NGLs and gas production in the 2008 WEO is valid, however, this has subsequently been modified by the IEA.

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