An oil & gas company's reserves are usually assessed and reported on an annual basis as this gives an indication of the performance of said company in not only producing hydrocarbons but discovering and replacing those produced hydrocarbons for future development.

On occasion, the reserves numbers that a company reports will be used to generate finance via private or public placements of shares or through more traditional borrowing from the major banks and financial institutions. These finances may be raised to fund development of an existing discovery or possibly for further exploration of a promising block or region. In either case the organisations supplying the money, whether they be investors looking for growth and prepared to take some risk to get a high return on their investment, or lenders looking for a more 'guaranteed' but perhaps lower rate of return, are reliant on the quality of the reserves assessment that is carried out as it is upon this that they will base their decisions. There is therefore a need to 'match' the reserves assessment style to the end-users' requirements. The result is a proliferation of 'standards', 'classifications' and rules & regulations that vary from country to country and market to market. None of them are necessarily 'wrong' but each of them needs to be applied and interpreted in the correct context.

The much maligned SEC regulations are extremely conservative and very prescriptive allowing only for strictly defined "P1" reserves to be recognised (although in a probabilistic sense the reservoir parameter variables are generally more akin to a P75 level rather than the more conventional P90 that would usually be associated with 'Proven'). They do not allow for the reporting of any exploration upside and apply strict contractual requirements for 'reserves' to be recognised as such. The plus side of this approach is that there is a very high probability that the reserves reported will in fact be produced. The rules are the same for every company and therefore it can be argued that they provide a benchmark by which oil & gas companies can be compared on an annual basis. So why would we want to assess reserves and their inherent value any differently?

The answer is that the upside, whether it be undrilled exploration potential, or additional recovery from enhanced oil recovery techniques, infill drilling and marginal satellite additions to name but a few, is of great interest and needs to be assessed in some way. in order to decide whether to proceed with plans to develop or access this upside. Indeed, it is usually the case that the "P2" recoverable reserves and associated value are used for the purpose of internal business planning. This makes a great deal of sense as it would be self-defeating to design transport infrastructure, for instance, which was only capable of transporting a P90 flow-rate thus delaying the 'sale' of the hydrocarbons and diminishing their net present value. However, it is an obvious fact that as we move away from 'SEC style' "P1" reporting to "P2" (or "Probable") and even "P3" (or "Possible") 'reserves' the degree of uncertainty increases and that uncertainty encompasses many aspects of the business from the basic geology involved right through to government royalties and local economics. Probably the most commonly used reserves classification guidelines are the SPE/WPC and these do specifically cater for the uncertainties that surround the quantification of 'reserves' and resources.

This is where the balance between geological / engineering uncertainty meets the world of accounting and financial uncertainty. Two identical prospects / developments from a geological and engineering risking point of view will be prioritised differently if the fiscal or political uncertainties differ between the two. It is true to say that "Value is in the eye of the beholder!" (with apologies to Shakespeare)