Thirty-five years of accumulating plugging liabilities and declining production have created the need for new economic yardsticks and new planning considerations to fund asset retirement obligations. Measuring and reporting “holdback” and its adjuncts will facilitate better decision-making.

THE PROBLEM

In the context of a portfolio, asset retirement obligations (AROs) for a single well vanish into insignificance. However, 35 years of deferred plugging across much of the U.S. industry have accumulated so that the end of field life requires plugging not just the last producer but decades of temporarily abandoned wells. Operators plan to fund this burgeoning liability using cash flow, even as cash flow tapers and as AROs compound.

Decision-makers in the oil industry use economic yardsticks such as payout, PV10% and ROI to measure the characteristics of uneven cash flows — first, large investments and then declining returns. The end-of-life scenario for modern U.S. oil and gas fields presents the opposite situation though at a smaller scale — declining inflows then relatively large capital costs — and upends traditional economic yardsticks.
The cash flow from low-rate, late-life wells presents more risk than early- and mid-life flows; they vary much more with decline uncertainty, commodity prices, total operating costs, split between fixed and variable costs, and intermittent repair costs. Since the age and maturity of groups of wells tends to be correlated within an asset to be acquired or even within an entire portfolio, cash flows from other wells and assets may or may not be sufficient to plug wells\(^1\) as required by statutory, contractual, and ethical standards.

Instead of relying solely on current production, operators may gamble on a sale to avoid ARO or on additional development to delay and to fund AROs; both gambits involve meaningful risks not entirely consistent with the certainty of the liabilities.

When they have done so at all, evaluations and audits have used present values to measure the impact of plugging liabilities, but operators plan, instead, to pay for the growing costs out of cash flow. Cash flow coverage of the liabilities inverts years earlier than present value. Reliable investment decision-making in today’s reality requires explicit treatment of liabilities plus new cash-based economic yardsticks to measure their significance.

**Customary exclusion**

Plugging liabilities may appear in three business processes: financial statements, reserve reporting and acquisition/investment analyses. Accounting rules do explicitly require the inclusion of discounted liabilities on the balance sheet, but the relative magnitude of assets and liabilities says less about the relative timing of each. Reserve and acquisition analyses for both internal decision-making and for external reporting, both of which do consider relative timing, have historically given AROs little or no attention on several rationales:

- Salvage value probably covered abandonment costs,
- Discounting made the present value irrelevant, and

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\(^1\) For this discussion, I use AROs, “plugging wells” and “plugging liabilities” interchangeably even though total AROs can be meaningfully greater than the sum of individual well plugging costs. Retirement obligations, particularly in large fields, can include costs for shared lines and facilities beyond the cost of plugging individual wells.
Assets were commonly sold to someone else (without consideration for plugging liability) long before the time came to spend the money.

In my observation and experience, none of those assumptions remain viable.

The equipment being retired is routinely older and more decrepit than in years past. The kinds of equipment needed by the industry have evolved during the shale revolution, requiring more new pipe than used and more large pumping units than small. The overall pace of development has slowed enormously while the pace of retirements has accelerated. That is, the supply of suitable used equipment seems to outpace demand. Theoretically and anecdotally, these mean that salvage value does not and should not be expected to cover abandonment costs in the future.

Since AROs should be expected to require money out of pocket, the question becomes how best to bake those costs into planning exercises. Treatments have historically revolved around discounted present values, but present value may not be the most relevant measure. An operator actively making (successful) investments in a diverse portfolio may be able to rely on the balance sheet for assurance of ability to meet the compounding liability. In practice, however, portfolios of most operators are highly correlated, and incremental acquisitions/investments should be evaluated as standalone cash flows regardless of the contents of the portfolio.

“...portfolios can rapidly and “unexpectedly” capsize on a cash flow basis long before reaching the economic limit of production.”

Most U.S. production is very mature, and the large majority of unplugged wells already sit idle or continue producing at stripper rates. The secular trends of exploration and development systematically shrink opportunities for production while secular trends in finance wither capital available for investment. At this stage in the industry life cycle, the most common and most suitable strategy focuses on reducing costs and generating cash flow, not on growth. At industry-wide, company and projects levels, the question of paying for AROs functionally pivots from the balance sheet to the projected cash flow.
Buyers recognize these facts and increasingly — but not universally — consider AROs in their purchase analyses. Buyers also increasingly recognize the fact that net cash flow from late-life wells presents more inherent risk than from younger, higher-rate wells, and sellers can no longer count on buyers to ignore abandonment liabilities in their offer price. Already, the acquisition and divestiture market has systematically trended away from paying for upside potential, and now some buyers have (appropriately) begun to use higher discount rates and to include end-of-life liabilities.

The same environmental awareness which has already reduced access to capital will further force purchasers to incorporate plugging liabilities to their bids. Most millidarcy fields in the U.S. are many decades old and have already been subject to multiple rounds of attempted redevelopment and cost cutting. My research shows that, including recent shale wells, the active producers onshore U.S. average 35 years of age. In my observation, redevelopment upside often does not meet the criteria for Proved reserves, and those that do still necessarily involve more risk than Proved Developed Producing reserves.

It should also be noted that the future costs of plugging may well turn out to be higher than the historical costs. Minimal demand for plugging services has kept costs and availability at (or arguably below) a minimum level, so the uncertainty lies on the high side. When widespread plugging activities resume, the same macroeconomic supply-demand forces may be expected to force costs higher.

Also, a program of plugging should be expected to exceed the sum of the most likely costs. The distribution of plugging costs among analogous wells skews widely to the right. Individual historical plugging operations likely have fallen closer to the mode of the distribution, but a large program will experience more high-side instances and, therefore, realize a substantially higher average cost for the program as a whole.
Permission to exclude

The customary exclusion of AROs for onshore U.S. production has evolved and persisted in the absence of external strictures. After the price collapse of 1986, state regulators across the U.S. relaxed requirements on the timing of plugging in order to allow operators the opportunity for prices to recover, but regulations did not return to their previous standards when other activities returned to normal. Vague statutory requirements for plugging all wells remain. However, largely indefinite deferment renders them practically toothless. Statutory implied covenants to landowners similarly exist, but lease agreements do not address the timing of plugging systematically or explicitly. Moreover, landowners have rarely sued for compliance.

Formal standards for reserve analyses have, in theory, recognized those vague, external obligations, but, in practice, cash flows have excluded the costs because business plans excluded them. The Society of Petroleum Engineers suggests that retirement obligations should be included, but the guidance remains superficial and vague enough not to have changed practices. The Society of Petroleum Evaluation Engineers offers no explicit guidance to its members; it outlines only applicable principles. These treatments have not supported the historical pattern of effectively disregarding plugging liabilities, but they have accommodated the pattern.

The requirements on physical plugging — and thus on their inclusion in cash flows and business decisions — have been more intrinsic than enforced, but the prudence of including and measuring the impact of AROs is becoming clear.

Black swan inversion

Conventional methods of measuring the effects of plugging liabilities compare present values of assets, which decrease, and of liabilities, which increase. Whether summed in a cash flow analysis for engineering purposes or divided in financial statements, the impact of liabilities grows

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2 To be clear, plugging rules vary by jurisdiction, and the costs are not excluded in some cases. In Canada, operators escrow plugging funds when a well is drilled, and U.S. federal lands, federal offshore and state waters mostly regulate plugging much more rigorously. Some plugging activities are required in onshore jurisdictions like Texas, but those requirements are minimal, and liabilities do, in fact, accumulate.
approximately exponentially as assets mature. Toward the end of economic life, present value of the assets declines more rapidly and accelerates the impact of liabilities. This exponential-then-accelerating behavior creates a late-life reversal that seems obvious in retrospect.

U.S. operators do not maintain reserve funds to pay for plugging liabilities, and they do not promptly plug wells. Instead, they idle uneconomic wells indefinitely to defer expenses and to preserve option value. They plan eventually to pay for the liabilities out of cash flow. In practice, liabilities snowball, collectively coming due simultaneously when the last surviving well no longer turns a profit. Setting aside momentarily the question of the risks and correlations within that cash flow, the relevant question under this business practice revolves around cash flow and not present value. The late-life reversal occurs much earlier on a cash basis because the liability is not discounted.

For demonstration purposes, the table below shows the dynamics of the ratios of net income to liabilities over the last 20 years of productive life for a lease declining at 5% per year — similar to the average decline of existing oil fields — assuming constant prices and costs. The first column shows how the ratio of present values inverts in the last few years of economic life when all wells produce to the end of lease. The next column shows that the ratio of undiscounted values, still assuming all wells produce to the end, is much less generous. The liability maintains its full value through the years while net income tapers, causing the inversion to occur earlier.

More dramatic is the effect of shutting in wells and thus compounding the burden on the surviving producers. My research of public data suggests that approximately half of all unplugged, onshore wells currently sit idle waiting to be plugged. The highlighted path across the columns shows how cash coverage changes as the concentration of idle wells increases. On average across the country, the situation has slowly moved from the second column into the third column, doubled the liability, and implied (according to this demonstration) that all net income for the last decade of economic life must be dedicated to plugging.
What is worse, continuing the same practices will accelerate the problem in the future. For example, consider a six-well lease where three wells have already been shut-in in recent years. The productive life required to cover plugging costs has grown from five years to 10. Shutting in one more well over the next year or two increases the dedication to 13 years. The next shut-in, which is likely to be correlated to the fourth, increases the requirement to 16 years. Already tenuous, many of today's portfolios can rapidly and “unexpectedly” capsize on a cash flow basis long before reaching the economic limit of production.

**PROPOSAL: HOLDBACK**

**A new economic yardstick and its adjuncts**

As a starting point to foresee and prevent this shortfall, I propose that evaluators prepare and that decision-makers review a novel economic yardstick focused on cash flow analogous to payout, and I propose to call this yardstick “**holdback**.” Payout measures the time to recover the capital costs expended, cash on cash. Holdback measures in reverse the amount of time necessary to accumulate the funds to be expended. That is, holdback is the time period during which all net cash flow would need to be set aside (used or at least “held back”) in order to be able to pay for impending retirement obligations.
The natural extensions of holdback include consideration for the intrinsic risk of net income. It might be argued that set-aside funds could earn a return and thus reduce the amount and period of holdback. As a practical matter, though, the liabilities are paid contemporaneously out of cash flow and bear less intrinsic uncertainty, and the kinds of low-risk investments suitable for cash to cover current or near-term liabilities do not offer meaningful returns. Most importantly, the greater issue lies in the uncertainty of the predicted cash flow. As mentioned above, end-of-life cash flows are the riskiest in the life of the field. Liabilities could come due much sooner or much later than expected, after accumulating much less reserve than required or perhaps long after funds have been held back. It would be analogous and appropriate to apply a form of discounting to the end-of-life net cash flow to measure the impact of uncertainties. I propose that “discounted holdback” is the period of time for which discounted net income equals plugging liabilities.

These two measures beg a name for their complement. If “holdback” is the period during which income is dedicated to liabilities, then it is preceded by “distributable life” while there is “distributable net income” prior to holdback or to discounted holdback.

“Cash coverage” can be the term for future net income divided by total plugging liability (before consideration of acquisition cost) to provide insight to the risk to profit from the uncertainty in the estimates of AROs. If, for example, the cash coverage is only 1.2 then a 20% increase in the AROs would wipe out all profits. Also, given the certainty and magnitude of capital commitments for retirement, they should be included with acquisition/investment costs in return on investment (ROI) calculations to measure the magnitude of profits. The ROI that includes retirement obligations may
be more explicitly labeled “Return on investment, retirement” (“ROIR”), and it differs from cash coverage by including acquisition cost in the denominator.

To be clear, neither holdback nor any of its adjuncts represent a business plan any more than payout and discounted payout do. Instead, they represent merely yardstick measurements of the character of the cash flow useful to decision-making, such as in the following examples adapted from recent projects.

**Small Acquisition Example**

A client wanted to purchase a small group of producing wells in a vintage waterflood, but like many packages marketed in recent years almost half of the wells in the package were already idled with no identified prospect for future production. Cash flows assumed a modest plugging cost per well, and no field-level costs, as specified by the client. Production decline rates were modest in aggregate, and near-term prices close to $80 /bbl generated a monthly net income of nearly $100,000. Traditional rules of thumb would suggest a value near $5 million.

However, margins were exaggerated by high prices, so backwardated prices compounded with declining rates to cut the future economic life shorter than might be assumed, a mere 57 months. Front-loaded cash flow combined with back-loaded liabilities to create a present value 10% of only about $600,000. However, the holdback period necessary to fund the lump sum plugging liability ran 50 months, leaving only seven months of theoretically distributable cash flow. This undiscounted distributable future cash flow totaled only $400,000, ironically less than the present
value. What is more, applying discounted holdback at 15% left only three months of distributable life, and even a slightly lower oil price would cause this cash-flowing acquisition to be unable to fund its own plugging over the entire remaining economic life.

Large Portfolio Example

Underwriting a reserve-based loan examined a diverse package of a few thousand wells, but only about a third of the wells were currently active. Monthly cash flow was running over $3 million. Thin margins were, again, temporarily inflated by spot prices above long-term futures, and production decline rates were, again, low to modest. The largest handful of fields in the portfolio calculated economic lives of 15 to 40 years each while a few small cases ran out past the 60 years of calculation, and all cases included plugging costs of $25,000 per well consistent with recent experience. Aggregate cash flow forecasted rapid decline followed by a string of lump sums costs while cash flow remained low.

Undiscounted future cash flow totaled $100 million, including consideration for over $60 million of plugging liabilities scheduled after the economic limit for each case, but the PV10% of that decades-long $100 million totaled only slightly less than the undiscounted figure. More dramatically, the rapidly declining cash flow and large liability meant that the holdback period came to over 55 years. That is, the period of distributable cash flow was projected to endure less than five years before all funds needed to be applied against retirement obligations. Taking a step further to consider a generic risk using a 15% discount rate, discounted holdback calculated to be 59 years. That is to say that if the operator plans to fund plugging from an uncertain cash flow, they can take less than a year's profit from the 3000-well portfolio before dedicating all proceeds over the long remaining life to retirement obligations.

Net Present Value and Rate of Return

As implied in the examples above, the unexpected effects of significant end-of-life liabilities distort the meaning and utility of standard net present value and rate of return yardsticks. A normal investment followed by a declining cash flow causes the present value to decline with increasing discount rate until the present value becomes negative at the rate of return. The blue line in Figure
4 shows this kind of normal trend of present value with discount rate though excluding the initial investment, which shifts the curve down to cross the x-axis.

Placing a (proportionally) major liability at the end of the cash flow changes the trajectory of present value with discount rate. The light red line shows how the example of the large portfolio trends much more shallowly with less difference in value over increasing discount rates. The dark red line representing the small acquisition goes so far as to invert the curve, with present value becoming ironically greater than undiscounted cash flow. The standard application of discount rate, and indeed even the idea of present value at all, becomes suspect as thinning cash flows end with substantial liabilities.

Figure 4: Net present value as a percentage of undiscounted cash flow for three scenarios.

Compounding and Evolving Uncertainty

These examples demonstrate holdback for single, deterministic forecasts of volumes, prices, and costs. However, modest and even small changes in production decline rate, operating costs, fixed/variable split of operating costs, price deck and repair costs can dramatically change the cash flow profile.

The production decline of late-life wells is often less well defined since less consistent rates obscure lower declines, and small changes in decline rate translate to large changes in reserves and revenue.
The exponential decline equation in continuous form states that shallowing decline rate from 15% to 13% increases reserves, productive life, and revenue by 15%. By comparison, shallowing from 7% to 5% increases the triad by 40%.

A third recent evaluation examined late-life gas production from a collection of thousands of wells with a shared facility on federal lands. In that case, simply re-allocating a portion of the operating costs from variable (i.e. decreasing with declining production) to invariable tripped the economic limit of the shared facility sooner, and it dominoed the prompt plugging of thousands of wells. The small change to the treatment – not magnitude – of current operating costs swung the net present value from a nine-figure positive value to a nine-figure liability. The client did not bid.

Even while production continues at high levels from recent wells, the plugging liability for the population of shale wells is maturing rapidly. Ultimate recovery has widely failed to meet expectations, chiefly due to greater-than-expected declines in mid to late life. Most evaluators now use terminal decline rates on shale oil wells greater than most decline rates from more permeable fields, suggesting economic limits sooner by comparison.

Although it includes its own unique idiosyncrasies, the grandfather of modern shale plays offers a directional warning about possibilities. Over 20,000 producers were drilled in the Barnett Shale, largely between 2008 and 2013. During most of the development phase, wells were widely expected to produce until 2060 or later. Already in 2021, i.e. 40 years ahead of schedule, one-third of the wells are shut-in, and operators face a serious question of holdback.

**RECOMMENDATIONS**

Today's systematic reality in the oilfield requires that executives, investors, and lenders see clearly the impact of plugging liability on their business plans and not just their balance sheets.

Professional engineering and accounting analyses must provide reliable insight to decision-makers and, above all, protect the welfare of the public. I make no recommendation here about the plans to be made or the weights to be placed on deliberations, but I do recommend the following to inform the decision process:
Reserve evaluators should report—as a matter of course even when they do not include plugging costs in their present value calculations—the quantum and source of asset retirement obligations as well as the implied holdback, discounted holdback and distributable life yardsticks.

Investment decisions should also consider the uncertainty of this deterministic holdback by calculating alternative scenarios with different input assumptions.

Standard-making organizations such as the Society of Petroleum Engineers and the Society of Professional Evaluation Engineers should consider creating more explicit and comprehensive guidance for reserve evaluations including, for example:

- explicit principles or rules for inclusion of AROs in cash flow analysis,
- more guidance on quantification of AROs,
- required discussion of sources and uncertainties in the estimate of liabilities, and
- recommendations for what levels of aggregation to use when calculating holdback.

Because business plans intend to pay for plugging costs out of cash flow, a cash flow measure of the liability serves better than a present value measure. Because operators intend to continue delaying and thus accumulating liabilities, many operators may now or soon face the prospect of insufficient future cash flow to fund AROs even though project life may still be run a decade or more. The right kind of measurement—holdback—forms the first step in understanding and addressing the risk that extends past a company's plans to its partners and to the tax-paying public. Because the alternative to funding AROs is filing bankruptcy.
APPENDIX A: HOW TO CALCULATE HOLDBACK

1. Sum all undiscounted costs scheduled to be incurred after the economic limit of the case or portfolio. This is the liability that must be balanced by held-back net income.

2. Beginning at the economic limit and moving earlier in time, sum the net income generated in each period, but also add any capital expenditures to the sum of liabilities.

3. Holdback occurs in the period when the accumulated undiscounted net income equals the projected, undiscounted capital costs.

4. The calculation should go on to consider the full projected life of the cash flow and designate holdback to begin at the earliest date that the two are equal. Plugging liabilities could be scheduled in such a way that the balance is achieved multiple times during the projection, and the most appropriate measurement is the most comprehensive holdback, not merely its final segment.

Discounted holdback follows the same procedure except that the total of accumulated net income is discounted with each time period before adding that period’s net income. Capital investments continue to accumulate through the calculation without discounting. On the first date that the two are equal, the risk-adjusted remaining net income equals the unrisked estimate of remaining capital spending.

The discount rate should reflect the inherent risk of the cash flow though perhaps reduced by any practical investment returns on the accumulated net income. I tentatively propose that a discount rate of about 15% to 20% would be most appropriate.

The calculation is suitable for both individual cases and groups of cases, for both Proved Developed Producing reserves and for totals of several reserve categories. Evaluators must, however, state the groupings used in the calculations.