Intelligent Completions at the Ready

The merits of intelligent completions are well documented, but their perceived high initial costs for design, installation and maintenance keep them out of many operators’ development plans. A new offering is likely to change that perception; these smaller, modular systems lower costs while retaining all the advantages of the larger and more-complex, high-tier systems.

Intelligent well systems were originally conceived in response to the extreme costs associated with certain well intervention operations in critical or remote areas, particularly in deep and ultradeep waters. The costs of workovers, recompletions and even some forms of basic maintenance on wells in water depths greater than about 150 m [500 ft] are often prohibitively high because these operations can be performed only from floating platforms.

Because such vessels are expensive to lease and to move, and subsea workovers are typically long term, operators are reluctant to contract a deepwater rig for a single workover or recompletion that does not promise significant return on investment. In addition, because these are often high-rate wells, the cost of lost production during shut-in may be a critical consideration when an operator is contemplating the merits of an intervention. Taken together, these factors often cause


Detecting water encroachment using downhole sensors. Because water influx at a zone causes a reduced production rate at that zone, the rates will increase in the other zones to ensure the well meets total well constraints, such as liquid rates or tubinghead pressure set by the operator. This change is manifested in a corresponding decrease or increase in pressure drop between zones. In this production scenario, at about Day 700, water breakthrough at the toe (blue) of a two-zone horizontal well creates a sharp decrease in pressure drop (red) between that zone and the sensor at the heel of the well. As water production increases from the heel of the well, around Day 1,160 (green), the pressure drop increases more slowly. At about day 1,700, with increasing water production from the heel, the pressure drop increases. (Adapted from Aggrey et al, 2008, reference 2.)
operators to postpone needed interventions. Such delays can lower production rates over an extended period of time, cause permanent damage to reservoir productivity and reduce ultimate recovery, all of which impact total field economics.

An intelligent completion (IC) can offer an alternative to interventions. ICs include downhole sensors that allow operators to gather flow and reservoir data remotely. They are equipped with remotely actuated downhole flow control valves (FCVs) with which operators can adjust flow from individual production zones. Remote sensors eliminate the need for the most common intervention in multizone wells: to identify the location of production-inhibiting problems such as water, gas or sand ingress. Sensors that measure changes in flow rate, temperature and pressure at specific well depths allow engineers to determine in real time which zone is experiencing production or pressure decline, without the expense and risk of an intervention (previous page).

Once engineers identify the source of a problem, they can then shut off, increase or decrease flow from any zone using FCVs placed across each production interval and reconfigure the completion. This may be especially cost-effective when initial changes to FCV settings must be further adjusted based on measurements taken during a flow period following the initial remedial operation.

When ICs were first introduced, companies resisted installing them. Engineers questioned, with some justification, the reliability of the systems’ critical components over the life of the well. Operators were equally wary of the capital expenditure (capex) of ICs, which has traditionally been substantially higher than that of conventional completions. As a result, economics and risk analyses often favored standard completions over ICs except in remote areas or for subsea completions.

Improvements in components and systems and years of IC use have done much to overcome industry misgivings about the reliability of ICs. However, because their design and implementation are complex, ICs remain relatively expensive. Consequently, their use continues to be restricted mainly to remote environments and in wells with very high production rates for which the cost of intervention and delayed production is extreme.

More recently, their appeal has widened as engineers have learned to use ICs as effective reservoir management tools. Multizone completions, waterfloods, gas lift and other systems are more easily optimized through remote downhole monitoring and control than through intervention. In many cases, the return on investment in ICs—through accelerated cash flow and increased ultimate recovery—far exceeds the savings realized by avoiding interventions. One major operator has calculated that 5% of the total economic impact of ICs on its business is due to savings on interventions, while 60% is due to reservoir-related revenue increases.
Engineers have also discovered that ICs can be instrumental in reducing the number of wells required to exploit a formation. Reducing well count, intervention frequency and intervention-associated delayed production can save operators millions of dollars in field development costs, particularly in deep water. Fewer wells also result in less subsea equipment and thus substantial reduction in capex. Additionally, water and gas processing units that service ICs may be smaller because excess water and gas production may be shut off or reduced downhole rather than treated on the surface. Zonal isolation and pressure optimization between zones result in higher rates of commingled flow to the wellbore. The consequence is a net increase in production and total recovery.

With surface-controlled FCVs, it is also possible to periodically measure reservoir and flowing bottomhole pressure (FBHP) without running production logs. This is accomplished by first closing one zone, which allows the downhole pressure sensor at the sandface to begin recording annular, or reservoir, pressure. At the same time, a sensor across a fully opened second zone measures the FBHP for that zone.

When the second zone is closed and the first zone is opened, sensors at the sandface measure the reservoir pressure of the second zone and FBHP from the first zone (above). This technique, which can be applied to a number of producing intervals at a time, allows operators to gather a downhole pressure profile from any zone at any time without excessive delays in production for buildup and without exposure to risk from interventions. This technique of isolating zones also enables engineers to collect formation pressure buildup survey information and a drawdown profile for productivity index (PI) updates and changes throughout the life of the well.

Despite proven reliability and a more broadly defined niche for ICs—and because the original intent of the developers was to use ICs in relatively high-rate wells—the economics of middle- and low-tier fields are such that operators continue to use traditional completion strategies rather than risk the capex of an IC. ICs were also intended to be robust enough to forestall intervention throughout the life of the well—usually more than 20 years—since a single intervention in deep water or other remote area could easily foil any anticipated economic advantage of an IC.

This design mandate resulted in ICs that were necessarily large, complex and costly. Additionally, over time, as industry providers sought to increase IC reliability and flexibility, the technology evolved piecemeal. Operators seeking best-of-class solutions often had to combine components from numerous suppliers within a single completion configuration. This created interface challenges that led to increased risk of equipment failure and wellsite time and costs to assemble, test and install completions.

All these factors have conspired to perpetuate the image of wells equipped with remote monitoring and control as large capital expenditures justified only by high-volume production, well complexity or locations where intervention is cost prohibitive or technologically problematic. This article describes redirected efforts that have given rise to a less complex IC system. Its design lowers its cost, which allows operators of average to marginal wells to reap the reservoir management benefits of ICs previously restricted almost exclusively to high-cost or high-risk applications.

The Value of Flexibility

When operators plan wells in deep water or other isolated locations, it may be clear that avoiding a single intervention saves enough in operating expense to justify the capital expense of a traditional IC. On the other hand, a single-zone, land-based well in an area well populated with rigs is unlikely to ever justify the expense of an IC even if the operator avoids numerous interventions.

During consideration of scenarios between those two extremes—for example multizone land-based completions—the cost analysis may not be so apparent. Shuttling off production from one zone and opening another through recompletion or by shifting a sliding sleeve are relatively low-cost propositions built into the original economics of multizone wells. However, such a strategy calls for the first zone to be depleted before the next one is opened. Reservoir analysis indicates that remotely adjusting downhole FCVs to commingle zones based on real-time pressure and temperature data significantly accelerates production and increases ultimate recovery compared with traditional on-off multizone completion configurations (above right).

This advantage is not always apparent because traditional discounted cash flow models used by most operators cannot quantify the value derived from operational flexibility. This flexibility depends on the availability of numerous options with which to mitigate well problems during the life of a well. Having the ability to remotely monitor downhole conditions and adjust flow from various zones in real time adds to the number of choices available to the operator, removing the economic burden of rig-based interventions.

Remote monitoring and control is a particularly powerful tool for reducing uncertainty in reservoir properties. For example, as with many deepwater developments, the operators of the Agbami field offshore Nigeria did not have substantial reservoir data on which to base well plans.

Agbami wells are typically completed in multiple zones within the same faulted reservoir. Pressure equilibrium indicated the zones are in communication, although uncertainties persisted in vertical and lateral crossfault connectivity under dynamic conditions (right). Consequently, engineers believed that waterflood and gasflood fronts would advance through the reservoir at different rates.

To manage this uncertainty, the operator installed ICs that included permanent pressure, flowmeter and densitometer sensors arrayed from the sandface to the separator. These are monitored through an integrated database and analysis computer that collects and evaluates sensor output. Variable chokes were placed downhole and at the surface to facilitate remote flow control.

The operator identified four categories that characterized the value added by using ICs:

- incremental recovery through optimized zonal contributions
- reservoir management through effective voidage replacement and pressure maintenance with gas and water injection
- optimized infill drilling through better models based on history-matching of zonal volumes rather than total reservoir volumes
- operating expense savings through reduction or elimination of workovers, sidetracks and production logging runs to evaluate injection and production contribution from individual zones.

Using dynamic simulation models, the operator concluded that the deployment of ICs on a field-wide basis at Agbami would deliver incremental oil recovery of 84 to 138 million bbl [13 to 22 million m³].

The Agbami field contains 20 producing wells, 12 water injection wells and 6 gas injection wells in about 5,000 ft [1,500 m] of water. Production in 2009 was 140,000 bbl/d [22,250 m³/d] of oil with peak production expected to be 250,000 bbl/d [39,730 m³/d]. Given its size, location and reservoir uncertainty, Agbami field was an ideal candidate for ICs. But the success there, in terms of incremental production as a result of IC installation, also demonstrates the potential advantages of the strategy holds for smaller fields if the initial capex can be recovered.

Small, Modular
In contrast to most IC-candidate wells—those characterized by multiple high-rate targets—many average to marginal wells are profitable only when operators are able to access numerous marginal production zones at the cost of a single wellbore. Despite the complexity inherent in drilling and completing many of these wells, project economics often demand that capex be strictly limited. This forces operators to exchange the reservoir management capabilities of an intelligent completion for the lower initial costs of traditional multizone completion configurations.

Schlumberger engineers have recently developed a technical solution to this market-driven issue by repackaging traditional, high-tier IC technology into a significantly lower-cost system. The IntelliZone Compact modular zonal management system was developed for deployment in multizone wells that require fewer choke positions and are of lower working pressures than those of traditional IC-candidate wells. It is suited for use in brownfields or marginal fields, in wells that would otherwise use sliding sleeve completions—most without monitoring systems—and wells requiring extended well testing. The IntelliZone Compact system improves recovery in long, horizontal wells by compartmentalizing them and controls zones in artificial lift wells by monitoring and controlling inflow at the sandface.

Smaller IC package. The modular design of the IntelliZone Compact system allows engineers to assemble and test the IC package for each zone before it is shipped to the wellsite. All electrical and hydraulic connections are welded into place by the manufacturer. Rig operators need only to connect lines at the handling subs and no longer must thread lines through packers and connect them to FCVs and pressure sensors on site, resulting in reduced installation time, cost and risk. A filter sub enhances system durability by preventing contaminants from reaching FCVs. In multizone wells, multidrop modules require fewer hydraulic lines to handle multiple control valves.

The IntelliZone Compact system is an integrated assembly rather than a conglomeration of the individual tools that make up traditional ICs. The downhole flow control assembly includes a packer, a handling sub and an FCV (left). FCVs may be either on-off two-position or four-position chokes. Each assembly can be tested at the factory and run with a production packer or an isolation packer without slips.

Using frequency shift keying (FSK) communication technology to transmit data to the surface, the system monitors downhole pressure, temperature and valve position every second. The data are transmitted to the surface control system via a single monococonductor cable. A hydraulic power unit (HPU) controls all hydraulic line fluid flow, inflow and pressures required to actuate downhole tools. A UniComm universal site controller functions as a data-gathering and control platform that operates motor control systems, downhole tool systems, SCADA and other communication systems.

The control system fulfills several key functions including acquisition and storage of tool data—annulus pressure, tubular pressure, annulus temperature, tubular temperature and FCV position. It also performs the automated sequencing of valve operations, alarm detection and conditions, tolerance levels, acquisition and storage of HPU data and remote SCADA capability.

The system relies on WellBuilder software for completion design to integrate the completion planning process from concept to commissioning. The WellBuilder program uses reservoir conditions, completion requirements and construction parameters to generate multiple configurations of the required number of control lines and operating pressure envelope limits for each zone.

IntelliZone Compact two-position FCVs include a flow control section and an actuator section. The two-position FCV may be either open or closed. A single actuation, accomplished by bleeding one control line while increasing pressure on another, changes the valve position from open to closed or vice versa. When more than one FCV is placed in the well, line sharing allows reduction of the number of lines to one plus the number of valves in the hole. The four-position FCV includes a choke and an actuator section plus a J-slot indexer, which controls the choke’s position; it can be closed, 35% open, 66% open or 100% open.

Like the two-position FCV, the choke position is changed one step per actuation by bleeding one line and pressuring up another and can also be configured for line sharing to minimize the number of hydraulic lines installed. The
A four-position FCV can also use a multidrop module that allows manipulation of up to three downhole valves through a single control line. A position sensor is integrated into the hydraulic FCV, which is accomplished by programming each FCV to react to a two-, four- or eight-pulse signal (right). Since the valves move in a single direction, a series of pulses may be used to change them from on to off or through the series of choke settings.

Minimizing the number of hydraulic control lines in a completion reduces installation complexity—fewer lines require less handling and splicing. The multidrop module also makes it possible to place FCVs at more production zones than would otherwise be possible because of a limited number of available packer or tubing hanger penetrations.

The multidrop module is externally mounted to the tubing within the IntelliZone Compact system and is connected to the open and closed ports of the FCV and, in series, to the hydraulic control line deployed to the surface. Downhole instrumentation can also be added to the flow control assembly as a modular package by mounting pressure and temperature gauges and other hydraulic devices around the tubing sub.

**Savings in Brazil and India**

The savings generated by the IntelliZone Compact system approach compared with conventional intelligent completions systems are derived from its modularity and standardization. At about 10 m [30 ft] long, it is half the length of standard ICs. Because the isolation device, sensors and flow control valves are packaged in a single assembly, there are no interface issues common to systems built from components supplied by multiple manufacturers. This significantly enhances total system reliability and, because the entire system is assembled and tested at the point of manufacture rather than in the field, it saves operator rig time.

The IntelliZone Compact system also helps operators save time and possible missteps because the control lines are installed as part of the package. Control line handling on site is limited to making splices above and below the package as it is run into the well. In standard applications, these lines must be threaded through the packers and connected to each control valve individually; this is a time-consuming operation fraught with opportunity to damage lines and components. Because fewer lines require handling, risk associated with splicing operations is also reduced.

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10. FSK communication technology uses a robust frequency modulation scheme that sends digitally encoded data by changing the frequency of a transmitted signal. A receiver converts the signal back to the original form. The FSK signal is easily connected to other communications devices such as those used by SCADA systems.
It was these time and cost savings that influenced a Petrobras decision to use an IntelliZone Compact system in the Carapeba-27 injection well of the Carapeba field in the Campos basin offshore Rio de Janeiro. Engineers sought to optimize production from this mature field by replacing conventionally completed, one-zone wells with IC three-zone wells. They chose to use an IntelliZone Compact IC in an injector well to optimize reservoir sweep and to perform injectivity tests to allocate injection rates in each zone. Both objectives are facilitated by the system’s highly accurate position sensor. Engineers also needed to monitor and control downhole flow remotely through their SCADA system, which was accomplished through the UniConn site controller.

Assembled and tested at the factory, each component of the three-zone modular completion included an isolation or production packer, a dual pressure and temperature gauge for tubing and annulus reading, a multidrop module, a two- or four-position FCV and an FCV position sensor. Since Carapeba is a brownfield, its project economics demanded a low-cost system, which was achieved by installation costs that were less than those estimated for traditional ICs (above).

Engineers with an offshore India operator also turned to an IntelliZone Compact solution as it considered how to complete a three-zone well within the economic restraints of a marginal field. They sought to reduce capex by using already purchased equipment. At the same time, they sought optimum return on their investment through control of each zone independently. Given these two constraints, their completion choices were between sliding sleeves and a surface-controlled downhole flow control system.

Sliding sleeves require interventions to shift them, and engineers knew that to bring these wells online they would have to perform coiled tubing–conveyed acid treatments across each zone individually. The alternative—treating all three zones at once—would have resulted in most of the acid entering one high-permeable zone while leaving the other two untreated. Use of traditional surface-controlled flow control systems to isolate each zone was not possible because operation of control equipment for three zones would require more hydraulic lines than existing penetrations in the company-owned wellhead.

The solution included deploying a multidrop module in an IntelliZone Compact system. Engineers were able to deploy surface-controlled downhole FCVs across all three zones using a single hydraulic line. The systems were deployed with a casing hole packer and two swellable packers to isolate each zone (next page). Using the multidrop module, engineers could open one zone while the other two were closed, ensuring that acid treatments were reaching their targets.
The elimination of three of the four control lines required by traditional systems and of the need for coiled tubing–based interventions saved the operator three weeks of rig time. As a result, the operator optimized production at 165% of the originally expected rate and saved US$ 1 million within the first two months following system installation.

**Low-Cost, High-Technology Solution**

Optimizing production requires investment. However, when faced with an asset of marginal reserves, operators are often left to choose only from basic completion scenarios for fear that any incremental production realized through higher technology will not be enough to pay the cost of such a solution. This is especially true when the challenge to increased production is as technical as that faced by engineers at PETRONAS completing a field offshore East Malaysia.

The PETRONAS-operated S-field contains marginal reserves in unconsolidated heterogeneous sandstone reservoirs. Reserves are in a stacked 40 m [131 ft] thick oil column. Because of the presence of a large gas cap, engineers feared breakthrough would prematurely end production and cause significant oil reserves to be bypassed. They also had to consider the possibility of water invasion from a moderately strong and active aquifer.11

To reduce well count while maximizing reservoir contact, PETRONAS engineers planned development of the field using 14 horizontal wells. Horizontal wells create a lower pressure drop at the sandface than do typical vertical or deviated wells with equivalent productivity. This lower drawdown helps reduce the severity of water coning and gas cresting.12

However, when the horizontal section penetrates zones of differing flow properties, those with higher permeability will deplete first. This can lead to water or gas entering the wellbore through the depleted sections of the producing zone, causing reserves in less permeable areas of the formation to be bypassed. Once such breakthrough occurs, rig-based remedial operations may be futile or may be unable to return oil production to economic levels.

Because zonal property contrasts were high, PETRONAS had to balance initial influx and maintain the ability to react to inflow problems later in the well’s life. To satisfy these requirements, IntelliZone Compact completions were considered as an alternative to passive inflow control devices (ICDs) for the other six commingled producers.13 Wells in the S-field best suited for the application were analyzed and ranked based on the well production profile and dynamic reservoir fluid properties such as water cut and gas/oil ratio. Different sandface production sensitivities for incremental oil, water-cut reduction, gas/oil ratio profile and FBHP were also performed.

The two wells chosen for the installation—Well-A1 and Well-A2—showed positive zonal inflow control analysis results compared with that of the base case of conventional stand-alone screens. They were completed with integrated modular completion packages that included zonal isolation packers, two intermediate and on-off position FCVs and permanent real-time pressure and temperature sensors.

The assemblies were delivered to the wellsite as a single joint less than 9 m [30 ft] long—one-half to one-third the length required for a comparable conventional IC. The assemblies were also pretested with electronics and hydraulic splices welded at the manufacturing center. Each tested connection was locked to the assembly and another metal strip was affixed to the housing to further protect the assembly and to guard against damage from shock during installation.

In addition to reducing the risk of installation failure, these practices shortened installation time by reducing the number of connections to be made and lines to be spliced on site. In the S-field case, installation rig time savings were up to two-thirds per zone compared with that of conventional installation, or the equivalent of about US$ 400,000 per well completed.

Following installation, wellbore nodal analysis combined with time-lapse modeling was used to predict production scenarios based on reservoir deliverability for proposed wellbore trajectories. Because detailed geologic and petrophysical properties for each well were unavailable from a history-matching model, these were calibrated from offset field performance. Production simulation results indicated how the IntelliZone Compact ICs would enable zonal production and control in

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Chen et al, reference 5.
various reservoir deliverability and production scenarios. The systems would be especially effective in controlling inflow from high PI zones by using a smaller valve opening, while encouraging low PI zones to flow through a fully opened valve. The IntelliZone Compact design includes options for three sizes of FCVs, each with fully open, fully closed and two intermediate choke settings. Based on reservoir simulation models, the valve assemblies were designed using the following selection criteria:

- zonal control for discrete zones
- flow balance from multiple zones
- crossflow prevention
- sufficient capacity for zonal PI differences.

Engineers used integrated field modeling software that provides material balance, nodal analysis and system performance analysis to compare the estimated ultimate recovery for the wells completed with IntelliZone Compact systems. They studied two production scenarios—potential production gain and downhole water and gas shutoff.

Under the first scenario, compared with passive ICDs, engineers found that active downhole flow control resulted in an additional 15,900 m$^3$ (100,000 bbl) of oil (above). Analysis of the second scenario, focusing on downhole gas and water cut, indicates potential gain in ultimate recovery. Field modeling software providing material balance, nodal analysis and system performance was used to compare estimated ultimate recovery for wells in the PETRONAS-operated S-field. The well was completed with surface-controlled downhole FCVs (blue) and compared with a well equipped only with a passive ICD (green). The FCV-equipped well is projected to ultimately recover 100,000 more barrels of oil than the ICD-equipped wells. (Adapted from Chen et al, reference 5.)

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<th>Zone 1 Opening, %</th>
<th>Zone 2 Opening, %</th>
<th>Tubular, psi</th>
<th>Annulus, psi</th>
<th>Pressure, psi</th>
<th>Tubular, psi</th>
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<th>Pressure, psi</th>
<th>Flow rate, bbl/d</th>
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^ Flow control configurations. Measuring zonal production with downhole pressure gauges, engineers studied seven control valve configurations for two zones in Well-A2 in the S-field. Case 0 established production with both zones fully open. In Cases 1 and 2, by shutting off production from Zone 2 and then Zone 1, respectively, the operator established the PI and water cut for each zone. Using the results of Cases 0, 1 and 2, engineers were able to discern that because of its low PI, Zone 1 did not contribute any production when both FCVs were fully open. After testing other combinations, the team concluded that Case 3, in which the valve controlling Zone 1 is 33% open and the valve at Zone 2 is 100% open, was the optimum configuration. (Adapted from Chen et al, reference 5.)
water management, indicated that production-ending water breakthrough would occur from the smaller, more permeable reservoir at the well’s heel. By shutting off that zone and opening the thicker, less permeable zone at the well’s toe, production would continue.

Using pressure buildup survey data, FBHP and surface well tests, an asset team studied productivity and zonal reservoir deliverability in Well-A2 to better understand the reservoir. Zonal contribution was monitored using permanent downhole pressure gauges, and production was adjusted through FCVs at each zone. After studying seven configurations, the asset team determined that 33% and 100% openings on Zones 1 and 2, respectively, created optimum flow (previous page, bottom).

The asset team compared a production profile of Well-A1 with one in an offset horizontal well completed in the same sand (above). The former showed a prolonged period of high net oil production while water and gas breakthrough was deferred. The latter suffered from a fluctuating lower oil rate coupled with accelerating water encroachment.

**Technical Solution to a Market Problem**

For years, developers of oil industry technology have been stymied by an industry reluctance to adopt innovative solutions. Generally, user hesitancy, particularly regarding tools aimed at the upstream sector, has been grounded in a fear that the new system would fail when subjected to the harsh realities of the downhole environment. In time, misgivings about system reliability have been overcome, and such innovations as rotary steerable systems and expandable casing have become commonplace. The same can be said of the industry’s acceptance of IC technology.

Today, industry recalcitrance about ICs stems from financial concerns among operators uncertain about their marginal or maturing assets; operators must see sufficient production increases from remote downhole monitoring and control capabilities to justify the hardware’s initial costs.

The introduction of a modular system aimed at providing the industry with the advantages of a traditional IC at a much lower cost promises to satisfy that requirement. This change in perception will accelerate the adoption of IC technology throughout the industry and, in doing so, significantly impact how operators view their marginal and mature fields.

With the cost barrier to entry lowered, ICs may extend the life of marginal fields because the technology to control production at the sandface, without interventions, leads to higher net production and ultimate recovery through more efficient commingling. Similarly, projects with economic scenarios so fragile that they were shelved for fear the cost of probable future interventions would negate net profit may now be brought forward. By using ICs in these marginal projects, operators can save on interventions and reduce initial capex for ancillary facilities. The ability to manage reservoir parameters by controlling flow to slow water ingress at the sandface also allows operators to plan smaller surface facilities and reduce water-handling costs, both of which have significant impact on aging or marginal field development plans.

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