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Research article

Abnormal liquid loading in gas wells of the Samandepe Gasfield in Turkmenistan and countermeasures

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Abstract

With complicated formation mechanisms, liquid loading in gas wells during gasfield development may significantly affect the productivity of gas wells and the ultimate recovery rate. Dynamic monitoring data of the Samandepe Gasfield in Turkmenistan shows that liquid loading can be found extensively in gas wells. Their formation mechanisms and negative impacts on gasfield development severely restrict the productivity enhancement of this gasfield. With their origins taken into consideration, liquid loads in gas wells were classified into three types: formation water, condensed liquid, and external liquid. By using the hydrostatic pressure gradient method and through PLT monitoring, properties of liquid loads in the Samandepe Gasfield were determined. In addition, formation mechanisms related to liquid loading in gas wells were obtained through analyses of critical fluid-carrying capacities and by using gas-reservoir production data. The following findings were obtained. Liquid loading was commonly found in this gas well with majority of reservoir formations in lower well intervals flooded. However, the formation mechanisms for these liquid loads are different from those of other gasfields. Due to long-term shut-down of gas wells, killing fluids precipitated and pores in lower reservoir formations were plugged. As a result, natural gas had no access to boreholes, killing fluids were impossibly carried out of the borehole. Instead, the killing fluid was detained at the bottomhole to generate liquid load and eliminate the possibility of formation water coning. Moreover, since the gasfield was dominated by block reservoirs with favorable physical properties and connectivity, impacts of liquid load on gasfield development were insignificant. Thus, to enhance the recovery rate of the Samandepe Gasfield significantly, it is necessary to expand the gasfield development scale and strengthen the development of marginal gas reservoirs.

Keywords: Turkmenistan; Samandepe Gasfield; Development; Gas well; Abnormal; Liquid loading; Formation mechanism; Impact; Countermeasure

1. Introduction

A certain amount of liquid usually loads in gas wells during gas-reservoir development. It comes from multiple sources, including formation water, condensate oil/water, and residual or flowback engineering fluid. Formation water invading the wellbore is the most common source. An additional hydrostatic pressure is created by the column of loaded liquid, which will lead to the decrease of producing pressure difference and gas production in turn. In addition, the reverse imbibition of loaded liquid will damage near-wellbore formations and further reduce gas productivity. Continuous building-up of liquid will eventually kill the gas flow, leading to the shut-down of gas wells, and reduction of the gas-reservoir recovery [1–3].

The Samandepe Gasfield in Turkmenistan, a giant structural edge/bottom-water gasfield, is a major gas supplier for the Trans-Asia Gas Pipeline and the Second West-East Gas Pipeline, straddling across the border of Turkmenistan and Uzbekistan. This gasfield, small in development-scale in the early stage, has provided an annual gas productivity of 55×10^8 m^3 rapidly until after 2009. And its development-

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scale should be further enlarged to improve its development efficiency. However, continuous dynamic monitoring indicates that liquid loading is common in the gas wells, possibly as the result of all-out formation water invasion, which severely affects the preparation of gasfield development program. Therefore, it is absolutely necessary to figure out the mechanisms of liquid loading in this area.

2. Overview of the gasfield

The Samandepe Gasfield is located in the central part on the right bank of Amu Darya River, Turkmenistan, and straddles across the border of Turkmenistan and Uzbekistan. Drilling activities have revealed Neogene, Paleogene, Cretaceous, Jurassic and Triassic–Permian formations from top to bottom. The key target is the Upper Jurassic Callovian–Oxfordian carbonate underlying a super-thick salt layer of 400 m, the regional cap of gas reservoirs in the area. The gas pool is a complete and gentle dome-shaped anticline structure with three sets of reservoir in total, namely limestone-anhydrite interbed (XVac), laminar limestone (XVp) and massive limestone (XVm), with an average burial depth of 2450 m. The pore-type gas reservoirs mainly consisting of bioclastic limestone, oolitic limestone and reef limestone, are medium–high porosity and permeability reservoirs (average porosity: 8.5%, average permeability: 74 mD), with inactive edge/bottom water. Natural gas is mainly composed of CH_4, with a low content of C_5^+ heavy hydrocarbons (about 0.31%), so it belongs to wet-gas reservoirs.

Discovered in 1960, the Samandepe Gasfield was firstly developed by the former Soviet Union in 1986, and shut in for storage in April 1993. This field has a producing pressure difference of 2–3 MPa, and single-well average production of 40×10^4–50×10^4 m^3/d. It has 28 producing wells in the peak development stage, with an annual gas production of 33×10^8 m^3, and has produced 166.2×10^8 m^3 gas cumulatively. It was handed over to Chinese operator in 2007. Two years later, its production was quickly recovered to 55×10^8 m^3/d through the Chinese operator's measures like reentry of old wells and addition of new wells.

3. Identification of liquid loading in gas wells

The common liquid loading identification methods can be divided into two categories: direct identification method [4] and indirect identification method [5]. The former can be used to identify liquid loading directly through instrument monitoring results. It is intuitive and highly accurate, with pressure-gradient and PLT monitoring methods as representatives. The latter can be used to discern liquid loading through the analysis of testing, production and other routine performance data. The indirect liquid loading identification method has lower requirements on data, and needs no special monitoring data. However, it may generate uncertain results, and multiple methods should be combined to obtain satisfactory results. Empirical production change method, tubing-casing pressure method, critical liquid-carrying method and well testing method are all typical indirect liquid identification methods. Some indirect identification methods can't be implemented due to high H_2S content and complicated downhole conditions in the Samandepe Gasfield, so direct methods are mainly used to identify liquid loading of gas wells there.

3.1. Pressure-gradient identification method

If liquid is loaded in a well, when the bottomhole pressure restores to a stable value after shut-in, abnormal gas–liquid pressure gradients per hundred meters or per meter would occur, with the column weight (density) being higher than pure gas column density. Fig. 1 is the hydrostatic pressure gradient monitoring curve of Well Sam-61. The figure shows that the section above 2430 m is full of gas, the section between 2430 and 2450 m has coexistent gas and liquid, and the section below 2450 m is full of liquid, which demonstrates that liquid has been loaded in the wellbore interval below 2430 m.

3.2. PLT monitoring method

PLT monitoring generally covers seven parameters, i.e., natural gamma ray, casing collar, turbine flow, fluid temperature, water holdup, fluid density and fluid pressure, which can be used to more accurately identify the situation of liquid loading. Fig. 2 is the composite PLT monitoring curves of 2413–2452 m section in Well Sam-61 in September 2011. There are two perforation intervals in this section, i.e., 2416.1–2427.6 m interval and 2431.6–2448.3 m interval. Flow curve slightly fluctuates in the wellbore section below 2446 m, indicating that only a small amount of gas was produced in the formations below, and most of the wellbore space was filled by liquid. In the 2446–2444 m wellbore section, the significant increase in turbine flow, the fluid density of 0.5–1.0 g/cm^3, and the drop of temperature show that a certain amount of gas is produced and gas–liquid, mainly liquid, exists in this wellbore section. In the 2444–2431.6 m wellbore section, the slightly increase of turbine flow and fluid density of 0.2–0.5 g/cm^3 demonstrate that a certain amount of gas produced in this section and gas–liquid, mainly gas exists in this wellbore section. In the wellbore section above 2431.6 m, the wellbore was full of gas.

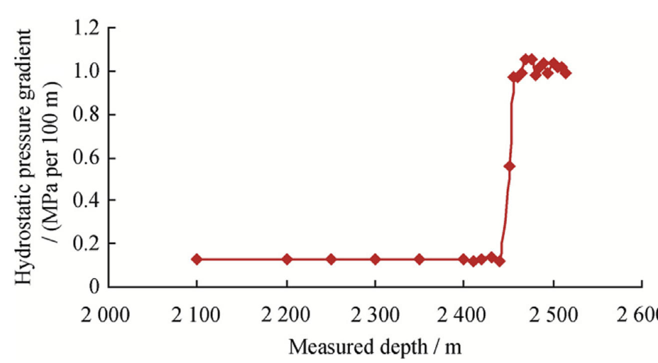

Fig. 1. Hydrostatic pressure gradient monitoring curve of Well Sam-61.

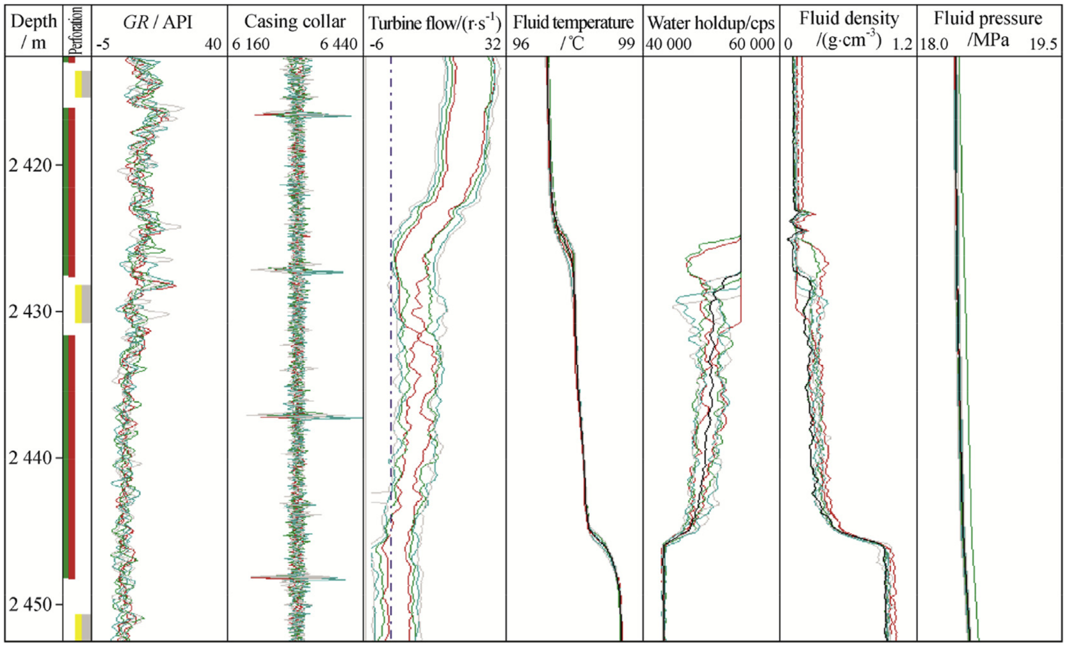

Fig. 2. Composite PLT monitoring curves of 2413−2452 m wellbore sections in Well Sam-61.

Liquid loading has been successively identified in seven wells by monitoring (Table 1), which is representative and universal in the plane, and causes great concerns.

4. Liquid loading types

4.1. Formation-water type

Free formation water flows into wellbore under the producing pressure difference, and liquid starts to load when energy of a gas well is not enough to carry the water out of the well. Liquid loading performance varies in different types of gas-reservoirs. For general edge/bottom water reservoirs, as edge/bottom water gradually invades into gas-producing reservoirs and finally into the bottom of the gas wells, the productivity of the gas wells would drop. Therefore, liquid loading has a strong negative impact on gas-reservoir development in the middle-late development stage. Most carboniferous gas reservoirs in the Sichuan Basin belong to this category. For low-permeability water-bearing reservoirs with poor pore structure and internal water, water is produced from the very start of well production; although the water production is at a low rate, liquid loading level would rise gradually as gas production is lower than the critical liquid-carrying capacity, so periodic foaming operation is needed to drain the loaded liquid and keep gas production normal. Most wells in the Daniudi Gasfield belong to this category. For fractured water-bearing gas reservoirs, as water rapidly flows into well bottom along fractures, the wells usually have high water production rate; if the gas production rate is high at the early production stage, the downhole water can be promptly carried to surface, but with the decrease of formation pressure and the increase of water production, liquid in the well would build up rapidly, and the productivity of the gas well would plummet or even fail to keep normal production. Most wells in the Weiyuan Gasfield belong to this category.

4.2. Condensate liquid

When gas containing water vapor and heavy hydrocarbon components flows into wellbore, condensate liquid would be

Table 1
Statistics on liquid-loading gas wells in the Samandepe Gasfield.

Well ID	Perforation interval/m	Date	Measured depth/m	Liquid loading	Liquid loading interval depth/m	Liquid loading interval height/m
Sam-61	2371−2494	2011-09-23	2502	Yes	2430	64
Sam-56	2401−2498	2011-12-17	2511	Yes	2471	27
Sam-67	2371−2470	2011-12-11	2447	Yes	2432	38
		2012-10-21	2447	Yes	2433	37
Sam-47	2401−2502	2012-06-17	2521	Yes	2496	6
		2013-04-16	2510	Yes	2494	8
Sam-60	2375−2468	2012-10-07	2480	Yes	2430	38
Sam-64	2412−2496	2012-10-10	2507	Yes	2449	47
Sam-54	2380−2501	2013-04-19	2476	Yes	2471	30

generated as the temperature decreases along the wellbore as a result of heat loss. Liquid would flow in the opposite direction of gas and accumulate at the well bottom when the flow rate of gas well is too low to carry condensate liquid to surface. For pure gas wells, condensate liquid loading can be judged by comparing the actual gas (oil) production and the theoretically-calculated condensate water (oil) production. Condensate liquid loading is created when the actual water (oil) production is lower than the theoretically-calculated condensate water quality. Condensate liquid loading usually occur in the development of condensate gas reservoirs, some liquid-loading wells in the Dalaoba condensate that this gasfield and Tarim condensate gasfield belong to this category.

4.3. External liquids

External liquids refer to drilling fluid, fracturing fluid, acidizing fluid and other operating fluids used in the exploration and development. These fluids get into formations during drilling, fracturing, acidizing and other operations and gradually flowback into wellbore in the early stage of production; when the gas flow is not high enough to bring the external liquid to surface, the liquid would load at the well bottom.

5. Abnormal liquid loading mechanism

5.1. Abnormal liquid loading confirmation

5.1.1. Analysis of liquid-carrying capacity

Liquid-carrying capacity analysis is the major and most effective method to judge liquid loading in gas wells. Scholars in China and abroad have made a lot of researches and proposed critical liquid-carrying models for gas wells with water produced and with different gas–liquid ratios, so as to predict liquid loading [6–10]. For gas wells with relatively high gas–liquid ratio, the commonly used methods include Turner critical liquid-carrying model and Li Min critical liquid-carrying model. Based on the assumptions of spherical liquid-drop and Newtonian fluid in wellbore, Turner derived the equation of minimum liquid-carrying velocity and production under continuous liquid drainage. However, in actual production, many wells can still keep normal production when the gas production is significantly lower than the critical production calculated by Turner equation. Therefore, the minimum gas production of liquid drainage calculated by Turner model is much higher than that of actual production. In 1991, Steve calculated the critical gas production by lowering the coefficient of Turner critical flow velocity and production equations by 20%, but the corresponding prediction results still had big discrepancy with actual production in some gasfields. Based on the assumption of flat-shaped water drop, Li Min deduced new equations to predict minimum liquid-carrying velocity and gas production of gas wells, which is generally believed to be a more practical method.

Turner critical liquid-carrying velocity:

$$v_g = 3.1 \times \left[\frac{\sigma g\left(\rho_L - \rho_g\right)}{\rho_g^2}\right]^{0.25}$$

Li Min critical liquid-carrying velocity:

$$v_g = 2.5 \times \left[\frac{\sigma\left(\rho_L - \rho_g\right)}{\rho_g^2}\right]^{0.25}$$

Where, v_g is critical liquid-carrying velocity, m/s; σ is interfacial tension, N/m, 60 mN/m for water; g is gravitational coefficient, N/kg; ρ_L and ρ_g are liquid and natural gas density respectively, kg/m^3.

According to the parameters obtained from Well Sam-61, the gas relative density and tubing inner diameter were set at 0.65 and 0.1 m respectively, and Turner and Li Min models were applied to calculate downhole and wellhead critical liquid-carrying rate respectively, and the calculated results are shown in Table 2.

The gas wells already in production in the oilfield have a daily gas production rate of 40×10^4–80×10^4 m^3, which is much higher than the critical liquid-carrying rate. So, liquid loading would not occur in these wells according to the critical liquid-carrying rate theory.

5.1.2. Liquid-loading level

Twice PLT monitoring in Well Sam-47 and Well Sam-67 at a time interval of nearly a year show that the liquid loading level of two wells were almost invariable (Table 1) although no measures were taken in this period, which disagreed with the regularity of conventional liquid loading.

5.1.3. Production performance

Gas production curves of all gas wells with liquid loading show that the pressure, gas production and water production of these wells didn't change much, not conforming to the features of liquid loading gas wells. Fig. 3 shows the production performance of Well Sam-61 with liquid loading. Since the reperforating operation in October 2010, the average daily gas production rate has been stable at 51.6×10^4 m^3, and only relatively high chloride content was found in water analysis.

5.2. Analysis of abnormal liquid loading mechanism

The performance of liquid-loading gas wells in the Samandepe Gasfield is entirely different from that of liquid-loading wells around the world. Then, what causes the abnormal liquid loading of these wells? Where does the liquid come from? The above three features of gas wells with abnormal liquid loading suggest that the abnormal liquid loading in the Samandepe Gasfield is not attributed to formation-water liquid loading. Meanwhile, the temperature keeps almost constant and the pressure slightly decreases after the formation fluid flowing into wellbore in the development, the water-vapor containing capacity of natural gas increases and condensate water and condensate oil are impossible to

Table 2
Comparison of critical liquid-carrying rates calculated by different models.

Position	Turner model			Li Min model		
	Pressure/MPa	Temperature/°C	Critical liquid-carrying rate/(10^4 $m^3 \cdot d^{-1}$)	Pressure/MPa	Temperature/°C	Critical liquid-carrying rate/(10^4 $m^3 \cdot d^{-1}$)
Wellhead	14.9	60	24.5	14.9	60	11.16
Downhole	19.0	100	26.1	19.0	100	11.87

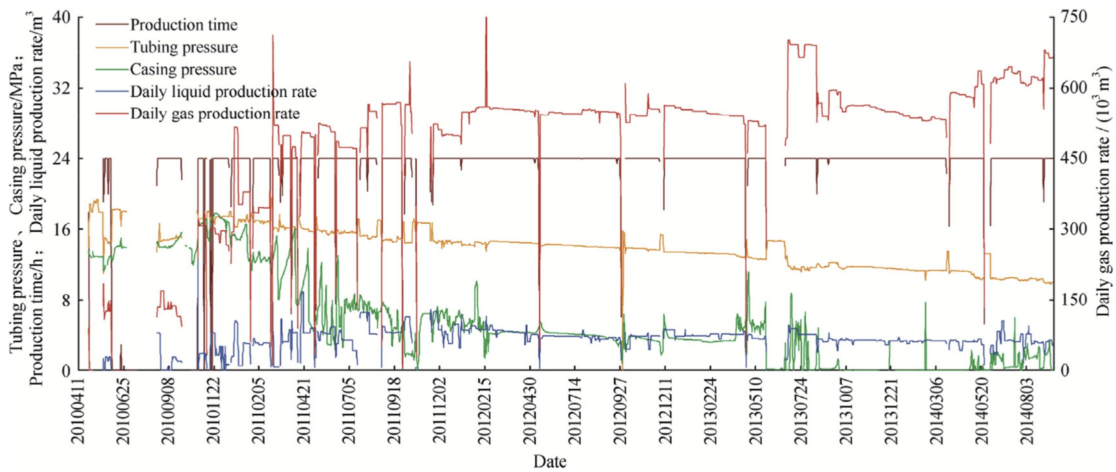

Fig. 3. Production performance of Well Sam-61.

precipitate. Therefore, the abnormal liquid loading in the Samandepe Gasfield is also not attributed to condensate liquid loading. After the possibility of formation water and condensate liquid loading is excluded, the abnormal liquid loading of gas wells in the Samandepe Gasfield can only result from external liquid loading.

Why does external fluid load in the wells? It can be seen from the distribution of gas reservoirs that the reservoirs mainly have better reservoir-quality and connectivity. Why is there so much difference in the same reservoir? According to the PLT monitoring data, gas production is dominantly contributed by the reservoirs above liquid-loading interval. The liquid-loading intervals have either low or no gas production and are severely polluted. Cross-checking shows that the gasfield was forced to shut down and the gas wells were shut in due to the limited purifying capacity. According to the

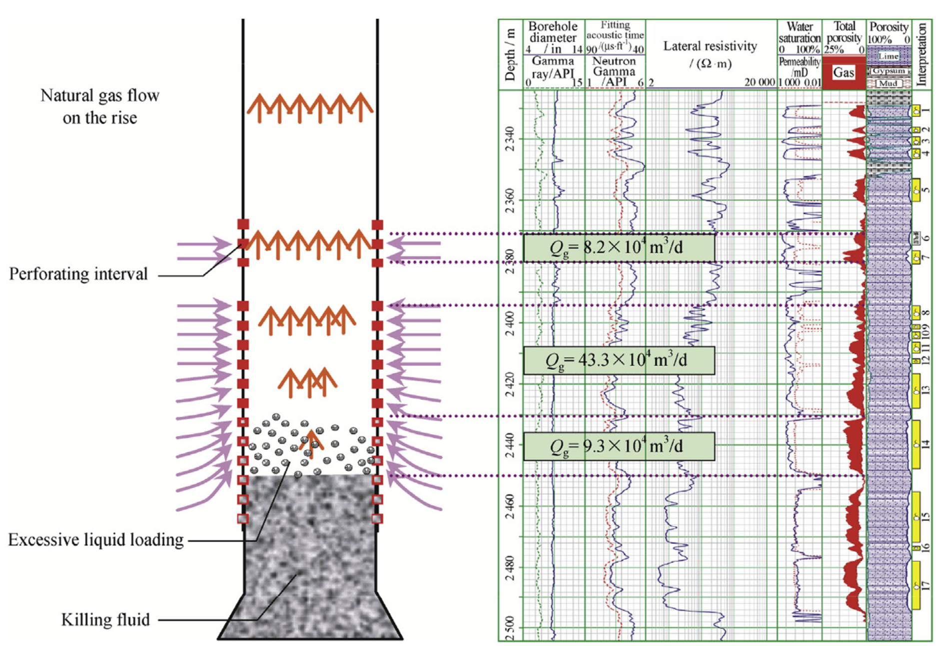

Fig. 4. Liquid loading mechanism of a gas well (1 ft = 0.3048 m).

Turkmenistan development regulations, the gas wells should not have pressure at wellhead when shut-in. Therefore, the gas wells were repeatedly killed during 16 years from 1993 to 2009. The killing fluid attaches to the sidewall or invades into formation, leading to severe damage to the reservoirs, and blocking of the natural gas from flowing into wellbore. Accordingly, the damaged intervals have barely gas production, and the residual killing fluid cannot be carried to surface either, resulting in universal liquid loading in most gas wells (Fig. 4).

Whether liquid loading will affect normal gasfield development? Although the relatively high liquid-loading level of some gas wells seemingly affects gas productivity and reserve producing [11], we believe, through analyzing the gas reservoirs, that the liquid loading will not cause a major negative impact on gasfield development. Performance monitoring shows that the gasfield dynamic reserves gradually increase year by year. The natural gas in the liquid-loading intervals can be recovered when it flows into the upper reservoirs due to relatively large thickness of gas-reservoirs, fewer interlayers between gas reservoirs and high permeability.

6. Countermeasures

The analysis of liquid loading mechanism in the Samandepe Gasfield shows that no edge/bottom water invasion has happened. The abnormal liquid loading will not have much negative impact on the gasfield development. The development scale can be further enlarged due to the high single-well gas production and stable productivity. On this basis, the gasfield development adjustment program has been rapidly made to take measures to enhance gas recovery rate. At present, the gasfield first-stage productivity enhancement project has been completed, and gas production and development efficiency have been raised to a higher level.

Given that the field has edge/bottom water, with the decrease of formation pressure in the development, the formation water energy and invading modes should be monitored closely. Gas-recovery technologies by water-drainage must be reserved in advance, and pressurizing project must be launched in time to ensure high-stable gas production and safe and efficient development [12].

7. Conclusions

(1) According to the fluid sources, loaded liquids in gas wells are classified into formation water, condensate liquid, and external fluid, etc.
(2) Downhole liquid loading is common in gas wells of the Samandepe Gasfield, but the well performance is entirely different from that of liquid loading in conventional gas wells.
(3) The abnormal liquid loading of gas wells in the Samandepe Gasfield results from long-term precipitation of killing fluid rather than formation water invasion.
(4) The abnormal liquid loading has little effect on the gasfield development, and the gasfield has the potential to enhance productivity further.

Fund Project

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