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Well blowout rates in California Oil and Gas District 4--Update and Trends

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Well Blowout Rates in California Oil and Gas District 4 – Update and Trends

a report by

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Well blowouts are one type of event in hydrocarbon exploration and production that generates health, safety, environmental and financial risk. Well blowouts are variously defined as "uncontrolled flow of well fluids and/or formation fluids from the wellbore"[1] or "uncontrolled flow of reservoir fluids into the wellbore".[2] Theoretically this is irrespective of flux rate and so would include low fluxes, often termed "leakage". In practice, such low-flux events are not considered well blowouts.[3,4] Rather, the term well blowout applies to higher fluxes that rise to attention more acutely, typically in the order of seconds to days after the event commences.

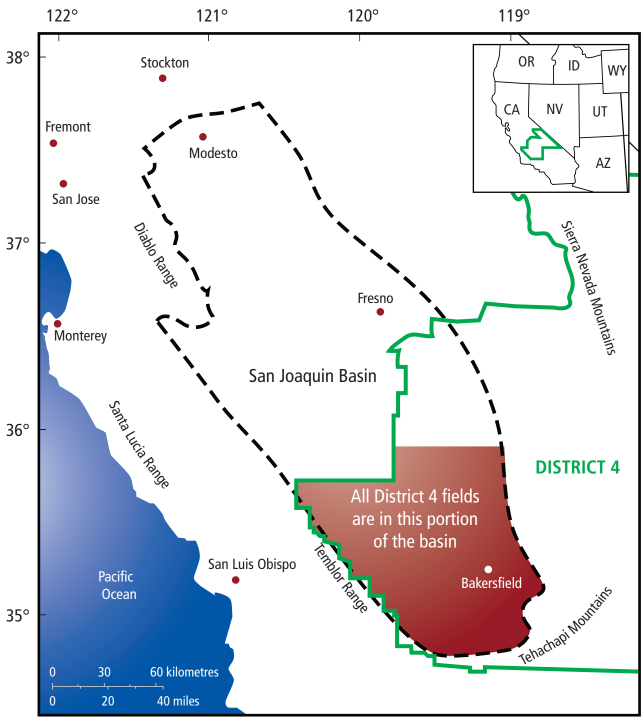
It is not unusual for insurance claims for well blowouts to exceed US$10 million.[5] This does not imply that all blowouts are this costly, as it is likely claims are filed only for the most catastrophic events. Still, insuring against the risk of loss of well control is the costliest in the industry.[5] Consequently, quantifying this risk is of considerable interest.

The risk of well blowouts was recently quantified from an assembled database of 102 events occurring in California Oil and Gas District 4 during the period 1991 to 2005, inclusive.[6] This article reviews those findings, updates them to a certain extent and compares them with other well blowout risk study results. It also provides an improved perspective on some of the findings. In short, this update finds that blowout rates have remained constant from 2005 to 2008 within the limits of resolution and that the decline in blowout rates from 1991 to 2005 was likely due to improved industry practice.

California Oil and Gas District 4

The oil and gas fields in District 4 are all located in the southern San Joaquin Basin shown in *Figure 1*.[7] Three-quarters of the oil production in California was from these fields during the study period. Three-fifths of the oil production in the District was via thermally enhanced recovery. Most of the fields in District 4 are in areas with low population densities, as shown in *Figure 2*. Some of these fields have a high density of steam injection wells for thermal recovery.

Figure 1: General Region of Oil and Gas Fields in California Oil and Gas District 4



Modified from Jordan and Benson, 2009[6] and Sheirer, 2007.[7]

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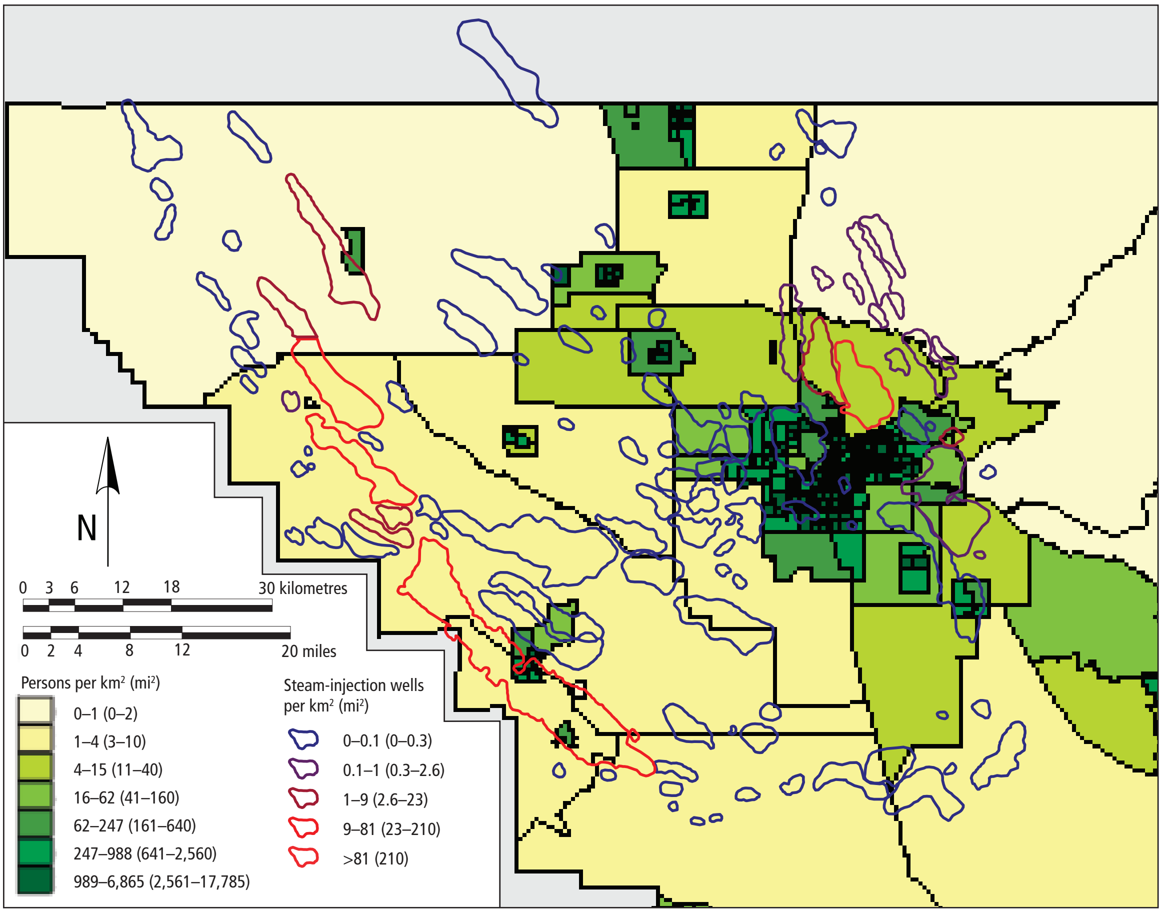
Blowout Rates and Comparison

The District 4 study[6] calculated blowout rates in a number of different categories. Based upon statistical significance testing in the study, though, these rates can be summarised and rounded somewhat for convenience, as shown in *Table 1*. This table also lists consequence information. Note the table does not include the blowout risk during well servicing because the appropriate basis (servicing operations) was not available.

The blowout rates for wells in operation ranged from one per 10,000 to 60,000 well-years. Blowout rates for oil and gas wells in operation in the combined Outer Continental Shelf of the US Gulf of Mexico and the UK and Norwegian waters from 1980 to 1991 have been reported as one per 20,000 well years.[8] A study of about three-quarters of the natural gas

Figure 2: Oil and Gas Fields in District 4 Relative to Population Density



Source: Jordan and Benson, 2009.[6]

storage wells in the EU prior to 2000 measured the blowout rates from these wells as one per 50,000 well-years.[9,10] These rates agree to within less than an order of magnitude, suggesting that operational well blowout rates are relatively constant from onshore to offshore environments and from primary production to enhanced recovery to gas storage.

Annual Blowout Update

The blowout data set assembled for the 1991–2005 study was updated by interrogating the same data sources for the 2006–2008 period: the annual reports, digital database and paper records of the California Division of Oil, Gas and Geothermal Resources, along with the Bakersfield Californian archive. No blowouts were described in the first source, two blowouts were listed in the second, six blowouts had records in the third and no blowouts were described in the fourth. The two blowouts in the second source were a subset of those from the third source. *Figure 3* updates the annual number of blowouts with the 2006–2008 data. This shows that the annual number of blowouts in the District stabilised at the quadrennial average at the end of the 1991–2005 study period.

District-wide Annual Blowout Trend

The annual number of blowouts in the District declined dramatically during the 1991–2005 period. As noted in the District 4 study, this could not be explained by changes in production activity in the District during the period.[6] *Figure 4* demonstrates this by superimposing the annual number of blowouts on the trend in different well-field activities, namely well construction, active wells and fluid volume. Well construction includes drilling, reworking and plugging and abandoning. Slightly more than one-third of blowouts occurred during these activities. About one-fifth of blowouts occurred during well servicing and one-third from wells in operation. The number of well servicing operations is not available, so active wells is a proxy basis for this category of blowout.

Fluid volume is also included in *Figure 4*. Fluid volume is the total amount of fluid injected and produced, including injected steam at wellhead conditions and produced water. Divided by the number of active wells, fluid volume is somewhat of a proxy for wellhead pressure, which has been posited as a primary parameter regarding well blowout rates.[6]

As shown in *Figure 4*, field activity in District 4 did not decrease during the study period. Therefore, the downward trend in the number of blowouts is due to some factor other than changes in activity within the District.

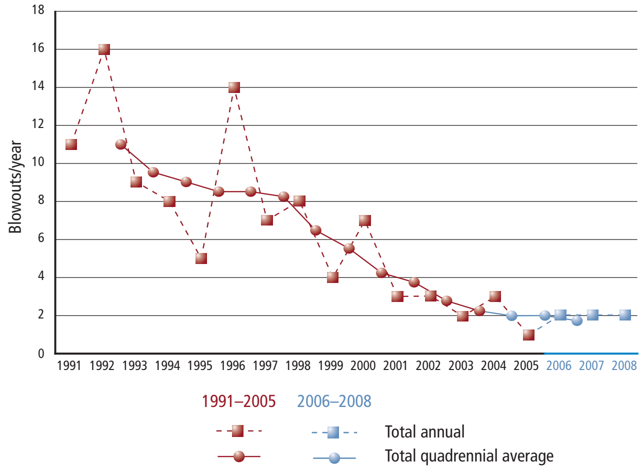
Specific Blowout Rate Trends

The annual and quadrennial average number of steam injection well blowouts and blowouts during well construction is shown in *Figures 5* and *6*, respectively. The number of steam injection well blowouts started decreasing in the late 1990s, and reduced to zero from 2001 to 2005. The number of blowouts during well

Table 1: Summary of Well Blowout Risks for California Oil and Gas District 4, 1991–2005

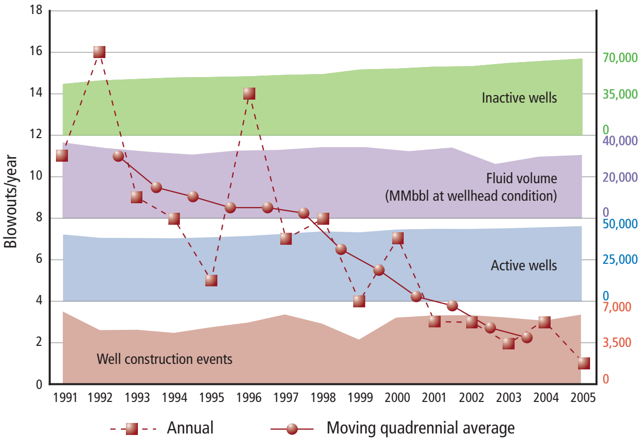
Blowout During/From	Probability	Consequences Affecting Public	 Causing Worker Casualty	 Affecting Environment	Duration Minimum	 Median	 Maximum
Well construction – non-thermal fields	1 in 2,500 wells	10% (oil-misted houses)	15% (fatality, severe burns, concussion)	20% (>25 acres affected)	30 minutes	18 hours	6 months
Well construction – thermal fields	1 in 1,700 wells	0%	10% (foot burn)	20% (<25 acres affected)	20 minutes	6 hours	43 hours
Non-thermal production wells	1 in 60,000 well-years	0%	0%	0%	3 hours		>1 day
Thermally enhanced production wells	1 in 20,000 well-years	20% (evacuation)	0%	60% (~25 acres affected)	4.25 hours	6 hours	12 hours
Steam injection wells	1 in 10,000 well-years	0%	0%	80% (primarily earth displacement – 1/3 to 400 cubic yards)	<5 minutes	2 hours	5 days
Shut-in/idle and plugged and abandoned wells	1 in 140,000 well-years	0%	0%	25% (displacement of up to 1,200 cubic yards of earth)	20 minutes	3 hours	5 hours

Figure 3: Updated Timeline of the Total Number of Well Blowouts in District 4



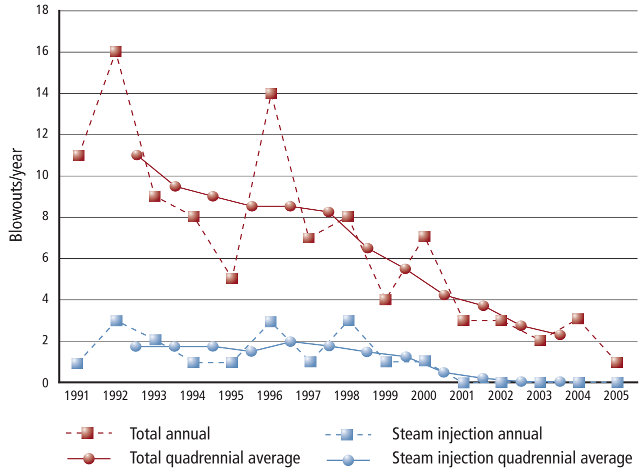
Modified from Jordan and Benson, 2009.[6]

Figure 4: Number of Well Blowouts Relative to Activity Through Time in California Oil and Gas District 4



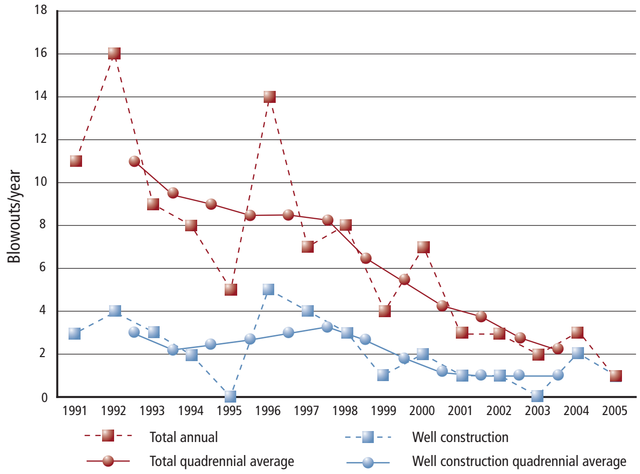
Modified from Jordan and Benson, 2009.[6]

Figure 5: Total Number of Well Blowouts and Blowouts from Steam-injection Wells in District 4 Over Time



Modified from Jordan and Benson, 2009.[6]

Figure 6: Total Number of Well Blowouts and Blowouts During Well Construction in District 4 Over Time



Modified from Jordan and Benson, 2009.[6]

construction declined from about three to one per year over the same time period. All six blowouts from 2006–2008 could be fully categorised with the available information. Three blowouts occurred during well construction. Two blowouts occurred from wells in operation – one each from a steam injector and thermal production well. One blowout occurred from an inactive well. The relative proportions of post-2005 blowout types are similar to the proportions of blowouts from 1991–2005, except for the lack of blowouts during

Table 2: Comparison of Selected Well Blowout Rates for 1991–1998 versus 2001–2008

	Well Construction		Steam-injection Wells		Inactive Wells	
	1991–1998	2001–2008	1991–1998	2001–2008	1991–1998	2001–2008
Coded blowouts	24	8	15	1	4	1
Normalised no. of blowouts	28.1	8.9	18.3	1.0	4.7	1.0
Basis	40,411	45,900*	108,190	100,000*	388,393	516,000*
Rate (%)	0.070	0.019	0.017	0.0010	0.0012	0.00019
Rate	1 per 1,400 wells	1 per 5,200 wells	1 per 5,900 well-years	1 per 100,000 well-years	1 per 83,000 well-years	1 per 520,000 well-years
p-value	0.00059		0.000087		0.086	

**2008 data were not available, so the 2001–2007 average was substituted.*

well servicing after 2005. The one inactive well blowout was similar to inactive well blowouts in the 1991–2005 study.[6] It was a steam-driven blowout from an abandoned well that created a depression by displacing a large quantity of earth onto the surrounding land surface. Site restoration required backfilling the depression with this soil and re-compacting it.

The rates of different types of blowouts from 1991 to 1998 and from 2001 to 2008 are listed in *Table 2*. Each rate is compared across the two time periods through the p-value. This is a measure of the likelihood of two quantities, in this case blowout rates, coming from the same normally distributed population. A p-value less than 5% is typically considered to indicate that two quantities are likely derived from two different populations. This is termed a statistically significant difference. When making multiple comparisons, however, there is an increased likelihood that any one comparison will meet the criterion of significance. One approach to resolve this is to divide the established criterion by the number of comparisons. This is called Bonferroni's correction. Eight rate comparisons are tested in this paper (included those presented below), so the p-value criterion of significance with Bonferroni's correction is 0.625%. The p-value was calculated using the same approach as in the 1991–2005 study.[6]

As shown in *Table 2*, the blowout rates for well construction and steam injection wells in operation decreased significantly. The p-value for these is less than 0.625%. Consequently, the 2001–2008 blowout rates of one per 5,000 well construction events and one per 100,000 steam-injection well-years is the most current for the District, rather than the values in *Table 1*. The blowout rate from inactive wells also apparently declined. Inactive wells include shut-in wells and plugged and abandoned wells. The decline in the blowout rate from these wells is not statistically significant, though; the p-value is greater than 5%. The inactive well blowout rate of one per 150,000 well-years, as given in *Table 1*,[6] should be considered current for the District.

Table 3: Drilling Blowouts, Wells Drilled, Rates and Comparison p-values

	CA District 4		CA	TX
	1991–1998	2001–2008	1950–1990	1960–1996
Coded blowouts	11	3	52	502
Normalised no. of blowouts	12.9	3.2	52	510.8
Borings drilled	13,585	16,400*	101,578	475,400
Rate (%)	0.095	0.019	0.051	0.11
Rate per well	1 per 1100	1 per 5,200	1 per 2,000	1 per 930
p-value		0.0081	0.11	0.64

** 2008 data was not available, so the 2001–2007 average was substituted.*

Table 4: Drilling Blowouts, Feet Drilled, Rates and Comparison p-values

	CA District 4		TX
	1991–1998	2001–2008	1960–1996
Coded blowouts	11	3	502
Normalised no. of blowouts	12.9	3.2	510.8
Feet drilled (million)	25	40*	2,497
Rate per million feet	1 per 1.9	1 per 13	1 per 4.9
p-value		0.0036	0.031

**The 2008 basis data were not available, so the 2001–2007 average was substituted.*

Blowout rates during drilling are shown in *Tables 3* and *4*. The drilling blowout rate per well from 1991 to 1998 was statistically the same as in California from 1950 to 1990 and in Texas from 1960 to 1996, as demonstrated in *Table 3*.[1,11] As for well construction overall, the drilling blowout rate per well in District 4 from 2001 to 2008 was lower than from 1991 to 1998. The p-value was less than 5%, but just over the more stringent 0.625% criterion. The 2001–2008 drilling blowout rate of one per 5,200 wells matches the overall well construction blowout rate for the period, which was significantly lower even by the 0.625% criterion. So, it seems reasonable to consider the current drilling blowout rate in the District as one per 5,200 wells.

Drilling blowout rates are also frequently calculated on a footage drilled basis to somewhat account for differences in boring depth from region to region and through time. The drilling blowout rate per foot drilled from 1991 to 1998 was higher than in Texas from 1960 to 1996, but not significantly so (the p-value was lower than 5%, but much higher than 0.625%), as given in *Table 4*.[11] The drilling blowout rate per foot in the District from 2001 to 2008 was significantly lower than from 1991 to 1998 (p-value less than 0.625%). The drilling blowout rate of one per 13 million feet drilled can be considered current in the District.

Industry Efforts

The literature suggests that the downward trend in blowout rates is due to a variety of focused efforts by industry to reduce well failures and improve well-field safety. For instance, the performance of steam-injection wells was improved by developing better cementing equipment and procedures.[12] These advances decreased cementing defects, which previously tended to leave sections of casing poorly supported or unsupported by cement in the annulus. This allows buckling and other casing failure modes due to thermomechanical stress.

The steam-injection well cementing improvements were first implemented in the field in 1995–1996.[12] The decline followed the first implementation of improved cementing procedures by approximately five years, which is in the order of the operational lifespan of a steam injection well.

At the same time as steam injection well cementing improvements were first being implemented, research to improve understanding of the geomechanical response of the diatomite reservoirs in the District to injection and production was reaching fruition.[13–15] At the time the well failure rate was 2–5% of active wells per year.[13] The goal of this work was to “suggest strategies for reducing the occurrence of well casing damage”, and the resulting study did develop such suggestions.

There are certainly causes other than poor cementing and geomechanically induced stress for blowouts from steam injection wells. Still, the timing and effectiveness of the process improvements described suggest that advances in industry practice did reduce the blowout rate from these wells. A study resulted in a similar conclusion regarding a decline in the blowout rate from wells in operation in a different industry in a different region of the world. The blowout rates measured from about three-quarters of the underground natural gas storage wells in operation in the EU prior to 2000 dropped by half from the 1980s to the 1990s.[9] This decrease was interpreted as resulting from improved procedures.[12]

Conclusions

Blowout rates due to well operations in California Oil and Gas District 4 from 1991 to 2005 ranged from one per 10,000 to one per 60,000 well-years, depending on the well field activity taking place at the time of the blowout. In District 4 the well blowout rate was one in 20,000 well-years for all wells in operation, with a rate of one per 15,000 well-years in thermal-recovery fields and one per 60,000 well years in non-thermal-recovery fields during this period. These rates are similar to those measured in offshore oil production in the Outer Continental Shelf in the US Gulf of Mexico combined with that in UK and Norwegian waters, and those in three-quarters of the underground natural gas storage wells in the EU.

The number of blowouts per year in District 4 declined by about 80% between 1991 and 2005.

The number of blowouts per year in District 4 declined by about 80% between 1991 and 2005. The decline in some rates has been statistically significant, with the well construction blowout rate down from one per 1,500 operations in the 1990s to one per 5,000 operations in the 2000s, and the steam injection well blowout rate down from one per 6,000 well-years in the 1990s to one per 100,000 well-years in the 2000s. There is circumstantial evidence that rates decreased due to improvements in production practice, such as improved cementing of steam-injection wells and management of geomechanical processes in reservoirs. These downward trends do not correlate with changes in production activity in the district. This demonstrates that risk in the hydrocarbon industry has and can be significantly reduced with focused effort. ■

Acknowledgements

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