Appendix 2.A

Tables for Section 2.4, Characterization of Well Stimulation Fluids

Table 2.A-1. Concentration and mass of chemicals used for hydraulic fracturing in California, as reported to the FracFocus Chemical Disclosure Registry prior to June 12, 2014. Includes a list of all chemicals from in 1,406 hydraulic fracturing treatments conducted in California between January 30, 2011 and May 19, 2014 that reported 100% (± 5%) of the chemical additives used in the treatment. Chemicals are reported by name and Chemical Abstract Service Registry Numbers (CASRN). Names of chemicals were normalized where possible, but chemicals reported without CASRN cannot be definitively identified. Some chemicals names are listed more than once if chemical was not identified by CASRN. Some compounds with multiple sources or purposes are listed more than once when purpose could be clearly differentiated (e.g., water used as base fluid vs. water in additive solutions).

Chemical Name	CASRN	No. of Times Reported	Median Conc. (mg kg^{-1})	95% of the Values are Below this Number (mg kg^{-1})	Chemical Mass Used Median (kg $treatment^{-1}$)	95% of the Values are Below this Number (kg $treatment^{-1}$)
1,2-Ethanediaminium, N1,N2-bis[2-[bis(2-hydroxyethyl) methylammonio]ethyl]-N1,N2-bis(2-hydroxyethyl)-N1,N2-dimethyl-, chloride (1:4)	138879-94-4	959	562	786	188	346
1,2,3-Trimethylbenzene	526-73-8	14	< 1	2	< 1	4
1,2,4-Trimethylbenzene	95-63-6	21	1	19	3	41
1,3,5-Trimethylbenzene	108-67-8	17	< 1	3	< 1	7
1-Butoxypropan-2-ol	5131-66-8	854	140	297	45	252
1-Methoxy-2-hydroxypropane	107-98-2	1	177	177	331	331
2-Propen-1-aminium, N,N-dimethyl-N-2-propen-1-yl-, chloride (1:1), homopolymer	26062-79-3	6	217	290	238	406
2-Propenoic acid, ammonium salt (1:1)	10604-69-0	1	4	4	22	22
2-Propenoic acid, ammonium salt (1:1), polymer with 2-propenamide	26100-47-0	1	125	125	736	736

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2-Propenoic acid, homopolymer, sodium salt	9003-04-7	6	109	123	127	153
2-Acrylamido-2-methylpropane sulfonate	38193-60-1	3	480	642	1,318	1,601
2-Butoxyethanol (Ethylene glycol butyl ether)	111-76-2	87	215	509	183	1,867
2-Butoxypropan-1-ol	15821-83-7	999	3	5	1	3
2-Ethylhexan-1-ol	104-76-7	83	< 1	1	< 1	< 1
2-Mercaptoethyl Alcohol	Proprietary	1	9	9	8	8
2-Methoxy-1-propanol	1589-47-5	1	2	2	3	3
2-Methyl-3(2H)-isothiazolone	2682-20-4	1,072	1	3	< 1	1
2-Methylbutyrate	600-07-7	2	< 1	< 1	< 1	< 1
2-Propenoic acid, polymer with sodium phosphinate (1:1), sodium salt	129898-01-7	82	76	349	57	354
2-Propenoic acid, polymer with sodium phosphinate (1:1), sodium salt	71050-62-9	2	< 1	< 1	< 1	< 1
5-Chloro-2-methyl-3(2H)-isothiazolone	26172-55-4	1,070	3	6	1	2
Acetic anhydride	108-24-7	36	36	389	30	735
Acetic acid	64-19-7	130	< 1	84	< 1	134
Acetyltriethyl citrate	77-89-4	80	186	657	191	941
Acrylamide	79-06-1	1	1	1	4	4
Acyclic hydrocarbon blend	Proprietary	23	1,500	3,632	454	2,883
Alcohols, C10-16, ethoxylated	68002-97-1	4	82	115	182	286
Alcohols, C10-14, ethoxylated	66455-15-0	83	22	35	17	33
Alcohols, C11 linear, ethoxylated	34398-01-1	10	4	227	4	169
Alcohols, C11-14-iso-, C13-rich, ethoxylated	78330-21-9	131	24	45	11	36
Alcohols, C12-13, ethoxylated	66455-14-9	4	31	36	2	4
Alcohols, C12-14, ethoxylated	68439-50-9	1	2	2	14	14
Alcohols, C12-14, Ethoxylated Propoxylated	Proprietary	23	125	303	38	240
Alcohols, C12-16, ethoxylated	68551-12-2	15	5	30	5	453
Alcohols, C7-9-iso-, C8-rich, ethoxylated	78330-19-5	119	300	1,681	168	723
Alcohols, C9-11-iso-, C10-rich, ethoxylated	78330-20-8	50	63	114	16	81

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Alcohols, C9-C11, ethoxylated	68439-46-3	10	2	152	2	112
Alcohols, Ethoxylated	Proprietary	2	23	24	103	107
Alfa-Alumina	Proprietary	1	374	374	1,500	1,500
Aliphatic alcohol	Proprietary	1	9	9	1	1
Aliphatic amide derivative	Proprietary	3	2	4	< 1	1
Aliphatic co-polymer	Proprietary	21	109	160	40	138
Aliphatic polyol	Proprietary	21	658	1,201	314	965
Alkanes / Alkenes	Proprietary	33	2,995	4,049	5,803	16,751
Alkenes, C>10 a-	64743-02-8	18	2	24	4	8
Alkyl Diamide	Proprietary	7	1	3	2	6
Alkyl dimethylbenzyl ammonium chloride	68424-85-1	12	22	35	29	506
Alkylalcohol ethoxylated	Proprietary	12	38	51	28	44
Alkylene Oxide Block Polymer	Proprietary	1	10	10	9	9
Aluminum oxide	1344-28-1	9	6,685	148,049	4,495	82,791
Amine derivative	Proprietary	10	461	708	143	534
Amine salts	Proprietary	58	< 1	541	1	909
Amino alkyl phosphonic acid	Proprietary	573	55	100	20	27
Aminotrimethylene phosphonic acid	6419-19-8	120	57	120	27	34
Ammonium bifluoride	1341-49-7	6	663	1,471	217	838
Ammonium Chloride	12125-02-9	46	129	28,210	273	27,408
Ammonium Persulfate	7727-54-0	1,299	63	377	23	247
Ammonium salt	Proprietary	27	238	494	349	2,919
Ammonium sulfate	7783-20-2	7	29	103	72	193
Ampicillin	69-53-4	105	6	12	2	4
Anionic Polymer	Proprietary	7	5	17	12	32
Anitfoam	Proprietary	6	< 1	< 1	< 1	< 1
Aromatic acid derivative	Proprietary	3	56	98	6	23
Aromatic Aldehyde	Proprietary	1	74	74	69	69
BC-3	Proprietary	93	175	379	189	1,056

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Benzenesulfonic acid, C10-16-alkyl derivs., potassium salts	68584-27-0	17	< 1	1	< 1	2
Benzyl Chloride	100-44-7	1	3	3	2	2
Biovert CF	Proprietary	6	2,097	2,604	3,102	4,765
Bis(2-ethylhexyl) sodium sulfosuccinate	577-11-7	83	10	16	8	16
bisHydrogenated Tallow Alkyl Dimethyl Salts With Bentonite	Proprietary	2	< 1	< 1		
Bis-quaternary methacrylamide monomer	Proprietary	5	48	90	80	857
Borate salts	Proprietary	12	495	723	366	670
Boric acid	10043-35-3	68	149	348	101	403
Boric acid, dipotassium salt	1332-77-0	66	945	1,666	660	1,979
Boron oxide	1303-86-2	48	119	470	53	614
Boron sodium oxide	1330-43-4	564	297	433	102	427
Bromic acid, sodium salt (1:1)	7789-38-0	2	237	409	103	181
Calcium chloride	10043-52-4	84	7	33	5	33
Caprylamidopropyl betaine	73772-46-0	6	28	37	44	95
Carbohydrate polymer	Proprietary	21	1,797	3,348	660	2,677
Carbohydrates	Proprietary	30	276	2,349	554	4,065
Cationic polymer	Proprietary	18	28	50	9	37
Cellulose, microcrystalline	9004-34-6	105	6	12	2	4
Ceramic materials and wares	66402-68-4	3	40,841	43,779	68,039	120,292
Chlorous acid, sodium salt (1:1)	7758-19-2	7	89	263	96	156
Choline chloride	67-48-1	31	700	1,328	266	1,473
Citric acid	77-92-9	40	128	600	229	647
Citrus Terpenes	Proprietary	1	365	365	245	245
Cocamidopropyl betaine	61789-40-0	6	275	367	439	948
Coco-amido-propylamine oxide	68155-09-9	16	1	367	1	948
Complex ester	Proprietary	2	251	438	215	409
Copolymer	Proprietary	2	321	332	96	133
Cristobalite carrier	14464-46-1	1,074	< 1	1	< 1	< 1
Cristobalite proppant	14464-46-1	3	7,403	45,366	4,140	40,862

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Crystalline silica quartz	14808-60-7	64	< 1	< 1		
Crystalline silica quartz carrier	14808-60-7	2,837	2	219	1	77
Crystalline silica quartz proppant	14808-60-7	1,551	231,626	333,535	91,527	340,777
Cured acrylic resin	Proprietary	56	21	168	11	38
Cured resin	Proprietary	20	8	26	7	22
Cyclic Alkanes	Proprietary	1	12	12	12	12
Cyclohexasiloxane, 2,2,4,4,6,6,8,8,10,10,12,12-dodecamethyl-	540-97-6	7	< 1	< 1	< 1	1
Cyclopentasiloxane, 2,2,4,4,6,6,8,8,10,10-decamethyl-	541-02-6	7	< 1	< 1	< 1	1
DBNPA (2,2-dibromo-3-nitrilopropionamide)	10222-01-2	22	14	963	22	1,720
decahydrate	Proprietary	2	< 1	< 1		
Decyldimethylamine	1120-24-7	39	3	4	1	4
D-glucitol	50-70-4	84	205	503	339	903
Diatomaceous earth, calcined	91053-39-3	1,761	27	281	8	91
Dicoco dimethyl ammonium chloride	61789-77-3	83	7	10	6	12
Diethanolamine	111-42-2	6	83	90	97	123
Diethylene glycol	111-46-6	85	1	4	1	5
Dioctyl sulfosuccinate sodium salt	Proprietary	12	38	51	28	44
Disodium ethylene diamine tetra acetate (impurity)	139-33-3	13	2	8	1	4
Disodium octaborate	12008-41-2	9	1,025	1,675	628	1,570
Distillates, petroleum, hydrotreated light paraffinic	64742-55-8	1,005	839	1,845	270	1,623
Dodecylbenzene	123-01-3	10	< 1	1	< 1	1
Dodecylbenzene	Proprietary	3	1	2	< 1	< 1
Dodecylbenzene sulfonic acid	27176-87-0	10	12	27	14	23
EDTA/Copper chelate	Proprietary	31	45	335	54	158
Enzyme G	Proprietary	477	578	1,301	193	955
Erthorbic acid	89-65-6	25	29	272	54	589
Ethanaminium, N,N,N-trimethyl-2-[(2-methyl-1-oxo-2-propen-1-yl) oxy]-, methyl sulfate (1:1), homopolymer	27103-90-8	11	33	279	31	467
Ethaneperoxoic acid	79-21-0	1	17	17	31	31

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Ethanol	64-17-5	26	28	600	20	556
Ethene, 1,1-dichloro-, homopolymer	9002-85-1	8	133	1,814	65	2,248
Ether	Proprietary	1	243	243	163	163
Ethoxylated	Proprietary	1	< 1	< 1		
Ethoxylated alcohol	Proprietary	9	6	64	7	15
Ethoxylated Alkylphenol (1)	Proprietary	1	74	74	37	37
Ethoxylated C14-15 alcohols	68951-67-7	105	103	135	135	179
Ethoxylated hexanol	68439-45-2	2	6	12	15	27
Ethoxylated nonylphenol	Proprietary	7	793	1,059	269	794
Ethylbenzene	100-41-4	10	591	1,154	769	1,889
Ethylene Glycol	107-21-1	1,064	306	428	97	210
Ethylene-vinyl acetate copolymer	Proprietary	2	42	73	36	68
Extract of yeast	8013-01-2	113	12	29	3	32
Exyalkylated amine	Proprietary	1	22	22	11	11
Fatty acid tall oil amide	Proprietary	14	5	30	5	453
Fatty acids	Proprietary	20	19	241	44	546
Fatty acids, tall-oil	61790-12-3	18	12	140	21	49
Fatty acids, tall-oil	Proprietary	1	2	2	15	15
Formaldehyde	50-00-0	21	< 1	5	1	10
Formaldehyde, polymer with 2-methyloxirane, 4-nonylphenol and oxirane	63428-92-2	3	5	6	13	13
Formaldehyde, polymer with 4-nonylphenol and oxirane	30846-35-6	50	47	85	12	60
Formic Acid	64-18-6	4	430	1,080	265	2,493
FRW-16A	Proprietary	13	116	390	248	878
Gelatin	9000-70-8	2	50	90	34	45
Glassy calcium magnesium phosphate	65997-17-3	16	153	583	204	216
Glutaraldehyde	111-30-8	96	66	203	99	373
Glycerol	56-81-5	240	128	878	27	838
Glycol	Proprietary	4	10	122	2	82

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Glycol ether	Proprietary	3	15	26	2	6
Glyoxal	107-22-2	84	614	1,509	1,016	2,708
GS-1L	Proprietary	1	1,482	1,482	1,650	1,650
Guar gum	9000-30-0	1,375	1,760	3,625	589	4,703
Hematite	1317-60-8	3	438	1,003	450	674
Hematite	Proprietary	1	56	56	225	225
Hemicellulase enzyme	9012-54-8	36	109	523	189	898
Hemicellulase enzyme	9025-56-3	977	16	46	5	50
Hemicellulase enzyme	Proprietary	109	25	36	32	49
Hexamethylenetetramine	100-97-0	88	17	3,291	14	2,348
Hydrochloric acid	7647-01-0	54	2,483	17,590	4,868	24,933
Hydrofluoric acid	7664-39-3	11	787	3,898	1,022	8,996
Hydrogen peroxide	7722-84-1	40	2	3	1	4
Hydrotreated Light Petroleum Distillate	64742-47-8	1,035	836	1,869	267	1,868
Iron	7439-89-6	2	< 1	< 1		
Iron oxide	1309-37-1	2	145	145	85	98
Isopropanol	67-63-0	154	503	1,884	268	976
Isopropylbenzene	98-82-8	17	< 1	< 1	< 1	1
Isotridecanol, ethoxylated	9043-30-5	1,039	139	290	44	211
Kyanite	1302-76-7	6	39,349	113,301	8,888	94,521
Lactose	5989-81-1	6	6	10	8	12
Lactose	63-42-3	6	1,560	1,661	2,002	2,268
Lecithins	8002-43-5	6	< 1	< 1	< 1	1
Linear/branched alcohol ethoxylate (11eo)	127036-24-2	10	8	17	9	15
Maghemite	1309-38-2	3	58	134	60	90
Maghemite	Proprietary	1	8	8	30	30
Magnesium chloride	7786-30-3	1,072	1	3	< 1	1
Magnesium iron silicate	1317-71-1	2	16,149	18,920	15,032	21,070
Magnesium nitrate	10377-60-3	1,072	3	6	1	3

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Magnesium silicate	1343-88-0	2	96,891	113,519	90,193	126,417
Mannanase, endo-1,4-beta-	37288-54-3	105	6	12	2	4
MBNPA (2-bromo-3-nitrilopropionamide)	1113-55-9	22	1	48	1	86
Methanol	67-56-1	602	384	934	276	1,294
Methyl salicylate	119-36-8	1	< 1	< 1		
Mixture of Surfactants	Proprietary	62	883	1,190	1,136	2,915
Monoethanolamine	141-43-5	13	1,900	2,297	3,662	6,270
Monoethanolamine borate (1:x)	26038-87-9	38	328	828	498	1,972
Mullite	1302-93-8	3	83,452	192,807	65,438	173,665
N,N-Dimethyldecylamine oxide	2605-79-0	39	189	260	56	255
Naphtha, hydrotreated heavy	64742-48-9	1	4,555	4,555	1,250	1,250
Naphthalene	91-20-3	94	6	11	1	9
Neutralized Polycarboxylic Acid	Proprietary	4	41	79	171	287
Octamethylcyclotetrasiloxane	556-67-2	7	< 1	< 1	< 1	1
Olefins	Proprietary	24	3	37	7	76
Oleic acid	112-80-1	83	< 1	< 1	< 1	< 1
Organic phoshonate	Proprietary	6	4,686	4,686	7,687	76,005
Organic sulfur compound	Proprietary	1	12	12	12	12
oxide	Proprietary	8	< 1	< 1		
Oxyakylated Amine Quat	Proprietary	24	528	812	239	881
Oxyalkylated alcohol (1)	Proprietary	21	38	51	12	44
Oxyalkylated alcohol (2)	Proprietary	20	1,328	2,193	319	1,513
Oxyalkylated alkyl alcohol (1)	Proprietary	9	72	98	21	74
Oxyalkylated alkylphenol (1)	Proprietary	24	134	242	95	360
Oxyalkylated alkylphenol (2)	Proprietary	25	120	238	92	359
Oxyalkylated amine	Proprietary	24	40	73	28	108
Oxyalkylated fatty acid	Proprietary	1	74	74	69	69
Oxylated alcohol	Proprietary	6	24	43	35	62

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Oxylated phenolic resin	Proprietary	8	242	711	92	559
Peroxidisulphate	Proprietary	2	< 1	< 1		
Petroleum Distillate Blend	Proprietary	146	3,329	5,504	4,236	5,072
Phenol, 4,4′-(1-methylethylidene)bis-, polymer with 2-(chloromethyl)oxirane, 2-methyloxirane and oxirane	68123-18-2	83	65	105	51	100
Phenol, polymer with formaldehyde	9003-35-4	206	3,154	13,511	1,583	11,174
Phosphonic acid	13598-36-2	693	2	3	1	1
Phosphonic acid	Proprietary	8	57	151	83	642
Phosphoric acid	7664-38-2	5	< 1	< 1	< 1	< 1
Poly (acrylamide-co-acrylic acid)	Proprietary	6	82	114	122	211
Poly ethylene glycol tridecyl ether phosphate	9046-01-9	12	16	30	9	23
Poly(dimethylaminoethyl methacrylate dimethyl sulfate quat)	Proprietary	1	37	37	6	6
Poly(oxy-1,2-ethanediyl), α(4-nonylphenyl)-αhydroxy-, branched	127087-87-0	4	65	119	74	93
Poly(oxy-1,2-ethanediyl), α[(9Z)-1-oxo-9-octadecen-1-yl]-α hydroxy-	9004-96-0	1	16	16	92	92
Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-	9016-45-9	26	909	3,623	600	2,244
Poly(oxy-1,2-ethanediyl), alpha-hexyl-omega-hydroxy	31726-34-8	95	173	243	141	265
Poly(oxy-1,2-ethanediyl), alpha-hydro-omega-hydroxy-, ether with D-glucitol (2:1), tetra-(9Z)-9-octadecenoate	61723-83-9	1	5	5	28	28
Poly(oxy-1,2-ethanediyl), alpha-tridecyl-omega-hydroxy	24938-91-8	50	< 1	< 1	< 1	< 1
Polyacrylamide copolymer	Proprietary	14	33	183	28	2,715
Polyethylene glycol	25322-68-3	50	14	25	3	18
Polyethylene-polypropylene glycol	9003-11-6	83	22	35	17	33
Polylactide resin	Proprietary	7	161	285	222	449
Polymer	Proprietary	12	8	12	6	11
Polyoxyalkylene	Proprietary	25	120	238	92	359
Polyoxyalkylenes	Proprietary	34	11	167	24	230
Polyquaternary amine salt	Proprietary	5	571	1,080	956	10,280
Polyquaternium 15	35429-19-7	1	8	8	6	6

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Polysiloxanes, di-Me	63148-62-9	7	< 1	< 1	< 1	1
Polytetrafluoroethylene	9002-84-0	65	< 1	1	< 1	1
Potassium acetate	127-08-2	83	< 1	< 1	< 1	< 1
Potassium bicarbonate	298-14-6	6	51	81	91	215
Potassium carbonate	584-08-7	260	949	4,149	1,209	6,487
Potassium chloride	7447-40-7	114	25	36	32	48
Potassium cis-9-octadecenoic acid	143-18-0	83	< 1	< 1	< 1	< 1
Potassium hydroxide	1310-58-3	222	49	522	55	530
Propan-2-ol	Proprietary	2	849	1,054	158	249
Propanol, 1(or 2)-(2-methoxymethylethoxy)-	34590-94-8	9	116	179	166	840
Propargyl alcohol	107-19-7	39	6	47	8	39
Propylene glycol	57-55-6	83	2	4	2	3
Quaternary amine	Proprietary	78	4	26	6	69
Quaternary ammonium chloride, benzylcoco alkyldimethyl, chlorides	61789-71-7	12	49	90	25	68
Quaternary ammonium compounds	Proprietary	20	30	73	22	139
Quaternary ammonium compounds, benzyl(hydrogenated tallow alkyl)dimethyl, stearates, salts with bentonite	121888-68-4	48	82	150	104	354
Quaternary ammonium compounds, benzyl-C10-16alkyldimethyl, chlorides	68989-00-4	50	31	56	8	40
Quaternary ammonium compounds, bis(hydrogenated tallow alkyl)dimethyl, salts with bentonite	68953-58-2	78	124	300	35	237
Resin coated cellulose	Proprietary	1	63,348	63,348	42,955	42,955
Salt	Proprietary	6	14	19	20	35
Secondary alcohols, C12-14, ethoxylated	84133-50-6	3	2	2,768	14	239
Sepiolite	63800-37-3	12	41	60	30	56
Silanetriol, (3-aminopropyl)-, homopolymer	68400-07-7	3	211	223	138	177
Silanetriol, 1-(3-aminopropyl)-	58160-99-9	3	35	37	23	29
Silica	7631-86-9	163	25	73	7	94
Silica gel	112926-00-8	48	17	30	21	71

Chemical Name	CASRN	No. of Times Reported	Median Conc. (mg kg^{-1})	95% of the Values are Below this Number (mg kg^{-1})	Chemical Mass Used Median (kg treatment^{-1})	95% of the Values are Below this Number (kg treatment^{-1})
Silicon dioxide (crystalline)	60676-86-0	1	40,465	40,465	33,758	33,758
Silicon dioxide crystalline	60676-86-0	1	31,972	31,972	11,409	11,409
Siloxanes and Silicones, di-Me	67762-90-7	7	< 1	< 1	< 1	1
Sodium bicarbonate	144-55-8	31	698	948	1,067	5,792
Sodium carbonate	497-19-8	1	1,102	1,102	2,542	2,542
Sodium chloride	7647-14-5	457	19	64	6	89
Sodium erythorbate	6381-77-7	12	19	42	18	36
Sodium glycolate	2836-32-0	13	5	25	4	12
Sodium hydroxide	1310-73-2	1,165	102	157	33	171
Sodium persulfate	7775-27-1	39	37	141	50	225
Sodium sulfate	7757-82-6	49	< 1	30	< 1	34
Sodium sulfite	7757-83-7	4	5	10	4	7
Sodium tetraborate decahydrate	1303-96-4	512	321	486	103	220
Sodium thiosulfate	7772-98-7	4	296	568	230	445
Solvent naphtha, petroleum, heavy arom.	64742-94-5	77	32	184	10	143
Solvent naphtha, petroleum, light arom.	64742-95-6	17	1	20	3	45
Sorbitan Monooleate	Proprietary	6	14	19	20	35
Sorbitan, mono-(9Z)-9-octadecenoate	1338-43-8	15	1	16	1	92
Sorbitan, mono-(9Z)-9-octadecenoate, poly(oxy-1,2-ethanediyl) derivs.	9005-65-6	14	1	6	1	91
Sulfate	Proprietary	4	< 1	< 1		
Sulfonate	Proprietary	26	72	103	97	887
Sulfuric acid	7664-93-9	11	< 1	1	< 1	2
Sulfuric acid	Proprietary	3	1	1	< 1	< 1
Sulfurous acid, sodium salt (1:1)	7631-90-5	6	18	21	21	25
Surfactant mixture	Proprietary	143	27	1,255	34	3,198
Talc	14807-96-6	128	1	5	1	3
Talc	Proprietary	1	< 1	< 1		
Tetrakis hydroxymethyl-phosphonium sulfate	55566-30-8	126	23	63	9	80

Chemical Name	CASRN	No. of Times Reported	Median Conc. (mg kg^{-1})	95% of the Values are Below this Number (mg kg^{-1})	Chemical Mass Used Median (kg treatment^{-1})	95% of the Values are Below this Number (kg treatment^{-1})
Tetramethyl ammonium chloride	75-57-0	7	22	243	19	114
Tetrasodium ethylenediaminetetraacetate	64-02-8	20	22	304	24	145
Thiocyanic acid, sodium salt (1:1)	540-72-7	1	4	4	24	24
Thioglycolic Acid	68-11-1	5	< 1	< 1	< 1	< 1
Thiourea, polymer with formaldehyde and 1-phenylethanone	68527-49-1	37	14	110	22	80
Titanium oxide	13463-67-7	2	145	145	85	98
Triethanolamine	102-71-6	92	315	942	212	647
Trimethyl borate	121-43-7	66	148	333	99	372
Trisodium ethylenediaminetetraacetate	150-38-9	13	2	8	1	4
Trisodium nitrilotriacetate	5064-31-3	13	1	4	1	2
Tryptones	73049-73-7	113	18	39	5	37
Unknown	Proprietary	11	663	690	876	890
Vinyl Copolymer	Proprietary	7	29	103	72	193
Vinylidene chloride/methylacrylate copolymer	25038-72-6	124	33	82	19	57
Water	7732-18-5	16	< 1	< 1		
Water additive	7732-18-5	2,173	464	2,272	147	2,837
Water base fluid	7732-18-5	1,208	747,943	841,445	272,980	1,367,950
Water base fluid	Water NOS	147	734,766	909,462	658,040	2,098,586
Water brine	Water NOS	8	742,081	974,567	1,060,074	6,780,217
Water KCL mix	Water NOS	20	775,902	992,581	619,345	1,426,289
Water produced	Water NOS	19	728,192	863,480	228,597	865,988
White Mineral Oil (Petroleum)	8042-47-5	2	42	73	36	68
Xylenes	1330-20-7	30	< 1	4,198	< 1	6,109
Zirconium oxychloride	7699-43-6	103	136	447	70	195

Table 2.A-2. Acute toxicity categories for oral and inhalation exposure. All values are expressed as LD_{50} (oral) or LC_{50} (inhalation). Adapted from the United Nations Globally Harmonized System of Classification and Labeling of Chemicals Fifth Ed. (United Nations, 2013, page 111).

Exposure Route	GHS 1	GHS 2	GHS 3	GHS 4	GHS 5
Oral (mg kg^{-1} bodyweight)	0 to 5	>5 to 50	>50 to 300	>300 to 2,000	>2,000 to 5,000
Gases (ppm V)	0 to 100	>100 to 500	>500 to 2,500	>2,500 to 20,000	---
Vapor (mg L^{-1})	0 to 0.5	>0.5 to 2	>2 to 10	>10 to 20	---
Dust (mg L^{-1})	0 to 0.05	>0.05 to 0.5	>0.5 to 1	>1 to 5	---

Table 2.A-3. Acute aquatic toxicity categories. Adapted from the United Nations Globally Harmonized System of Classification and Labelling of Chemicals Fifth Ed. (United Nations, 2013, page 222).

Exposure Route	GHS 1	GHS 2	GHS 3
48 hour EC_{50} for Crustacea (mg L^{-1})	≤1	>1 to 10	>10 to 100
96 hour LC_{50} for Fish (mg L^{-1})	≤1	>1 to 10	>10 to 100
72 or 96 hour ErC_{50} for Algae (mg L^{-1})*	≤1	>1 to 10	>10 to 100

**ErC_{50} is EC_{50} of growth rate*

Table 2.A-4. Compounds submitted to South Coast Air Quality Management District (SCAQMD) from matrix acidizing operations. Over 20 of these reported chemicals were not found in voluntary notices reported for hydraulic fracturing to the FracFocus Chemical Disclosure Registry (Table 2.A-1).

Chemical Name	CASRN	Also reported as used in hydraulic fracturing (Table 2.A-1)
1-Eicosene	3452-07-1	No
Pine Oil	8002-09-3	No
Toluene	108-88-3	No
Morpholine	110-91-8	No
1-Tetradecene	1120-36-1	No
1-Octadecene	112-88-9	No
Isoquinoline	119-65-3	No
Ammonium Fluoride ((NH4)F)	12125-01-8	No
D-Limonene	138-86-3	No
Nitrilotriacetic Acid	139-13-9	No
Acrylic Polymer	26006-22-4	No
Etidronic Acid	2809-21-4	No
1-Octyn-3-Ol, 4-Ethyl-	5877-42-9	No
Amines, Hydrogenated Tallow Alkyl, Acetates	61790-59-8	No
1-Hexadecene	629-73-2	No
Benzenesulfonic Acid, C10-16-Alkyl Dervis., Compds. With 2-Propanamine	68584-24-7	No
Benzenesulfonic acid, C10-16-alkyl derivs., compds. with triethanolamine	68584-25-8	No
Hydrocarbons, Terpene Processing Byproducts	68956-56-9	No
Petroleum Naphtha	68990-35-2	No
Potassium Iodide	7681-11-0	No
Phosphoric Acid, Calcium Salt (2:3)	7758-87-4	No
Calcium Bromide	7789-41-5	No
Quinaldine	91-63-4	No
Acetophenone	98-86-2	No
Ethylbenzene	100-41-4	Yes
Calcium chloride	10043-52-4	Yes
2-Ethylhexan-1-ol	104-76-7	Yes
Propargyl alcohol	107-19-7	Yes
Ethylene Glycol	107-21-1	Yes
Diethylene glycol	111-46-6	Yes
2-Butoxyethanol (Ethylene glycol butyl ether)	111-76-2	Yes
Ammonium Chloride	12125-02-9	Yes

Chemical Name	CASRN	Also reported as used in hydraulic fracturing (Table 2.A-1)
Sodium hydroxide	1310-73-2	Yes
Xylenes	1330-20-7	Yes
Phosphonic acid	13598-36-2	Yes
1,2-Ethanediaminium, N1,N2-bis[2-[bis(2-hydroxyethyl) methylammonio]ethyl]-N1,N2-bis(2-hydroxyethyl)-N1,N2-dimethyl-, chloride (1:4)	138879-94-4	Yes
Crystalline silica quartz	14808-60-7	Yes
Sodium carbonate	497-19-8	Yes
Formaldehyde	50-00-0	Yes
Polyepichlorohydrin, trimethyl amine quaternized	51838-31-4	Yes
Cyclohexasiloxane, 2,2,4,4,6,6,8,8,10,10,12,12-dodecamethyl-	540-97-6	Yes
Cyclopentasiloxane, 2,2,4,4,6,6,8,8,10,10-decamethyl-	541-02-6	Yes
Octamethylcyclotetrasiloxane	556-67-2	Yes
Glycerol	56-81-5	Yes
Silanetriol, 1-(3-aminopropyl)-	58160-99-9	Yes
2-Mercaptoethyl Alcohol	60-24-2	Yes
Fatty acids, tall-oil	61790-12-3	Yes
Polysiloxanes, di-Me	63148-62-9	Yes
Tetrasodium ethylenediaminetetraacetate	64-02-8	Yes
Ethanol	64-17-5	Yes
Formic Acid	64-18-6	Yes
Acetic Acid	64-19-7	Yes
Hydrotreated Light Petroleum Distillate	64742-47-8	Yes
Solvent naphtha, petroleum, heavy arom.	64742-94-5	Yes
Solvent naphtha, petroleum, light arom.	64742-95-6	Yes
Alcohols, C10-14, ethoxylated	66455-15-0	Yes
Methanol	67-56-1	Yes
Isopropanol	67-63-0	Yes
Siloxanes and Silicones, di-Me	67762-90-7	Yes
Silanetriol, (3-aminopropyl)-, homopolymer	68400-07-7	Yes
Ethoxylated hexanol	68439-45-2	Yes
Thiourea, polymer with formaldehyde and 1-phenylethanone	68527-49-1	Yes
Ethoxylated C14-15 alcohols	68951-67-7	Yes
Potassium chloride	7447-40-7	Yes
Silica	7631-86-9	Yes
Hydrochloric acid	7647-01-0	Yes
Sodium chloride	7647-14-5	Yes

Chemical Name	CASRN	Also reported as used in hydraulic fracturing (Table 2.A-1)
Hydrofluoric acid	7664-39-3	Yes
Water	7732-18-5	Yes
Sodium sulfate	7757-82-6	Yes
Ammonium sulfate	7783-20-2	Yes
Citric acid	77-92-9	Yes
Erthorbic acid	89-65-6	Yes
Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-	9016-45-9	Yes
Naphthalene	91-20-3	Yes
Citrus Terpenes	94266-47-4	Yes
1,2,4-Trimethylbenzene	95-63-6	Yes
Isopropylbenzene	98-82-8	Yes

Table 2.A-5. Chemicals reported no more than 10 times in voluntary disclosures. This table contains the unique names and Chemical Abstract Service Registry Numbers (CASRN) combinations from voluntary disclosures in California as reported to the FracFocus Chemical Disclosure Registry prior to June 12, 2014. Includes chemicals listed in 1,623 hydraulic fracturing treatments conducted in California between January 30, 2011 and May 19, 2014.

Chemical Name	CASRN	No. Times Reported
1-Methoxy-2-hydroxypropane	107-98-2	1
2-Propenoic acid, ammonium salt (1:1)	10604-69-0	1
2-Propenoic acid, ammonium salt (1:1), polymer with 2-propenamide	26100-47-0	1
2-Mercaptoethyl Alcohol	Proprietary	1
2-Methoxy-1-propanol	1589-47-5	1
Acrylamide	79-06-1	1
Alcohols, C12-14, ethoxylated	68439-50-9	1
Alfa-Alumina	Proprietary	1
Aliphatic alcohol	Proprietary	1
Alkylene Oxide Block Polymer	Proprietary	1
Alpha-(4-nonylphenyl)-omega-hydr oxy-, branched	Proprietary	1
Ammonium acetate	Proprietary	1
Aromatic Aldehyde	Proprietary	1
Bauxite	1318-16-7	1
Bauxite	Proprietary	1
Benzyl Chloride	100-44-7	1
Bis(hydrogenated tallow alkyl) dimethyl,salts with bentonite compounds	Proprietary	1
Citrus Terpenes	Proprietary	1
Corundum	1302-74-5	1
Cyclic Alkanes	Proprietary	1
Ethaneperoxoic acid	79-21-0	1
Ether	Proprietary	1
Ethoxylated	Proprietary	1
Ethoxylated Alkylphenol (1)	Proprietary	1
Exyalkylated amine	Proprietary	1
Fatty acids, tall-oil	Proprietary	1
GS-1L	Proprietary	1
Hematite	Proprietary	1
Maghemite	Proprietary	1
Methyl salicylate	119-36-8	1
Modified bentonite	Proprietary	1
Organic sulfur compound	Proprietary	1
Oxyalkylated fatty acid	Proprietary	1
Poly(dimethylaminoethyl methacrylate dimethyl sulfate quat)	Proprietary	1
Poly(oxy-1,2-ethanediyl), α-[(9Z)-1-oxo-9-octadecen-1-yl]-ω-hydroxy-	9004-96-0	1

Chemical Name	CASRN	No. Times Reported
Poly(oxy-1,2-ethanediyl), alpha-hydro-omega-hydroxy-, ether with D-glucitol (2:1), tetra-(9Z)-9-octadecenoate	61723-83-9	1
Polyepichlorohydrin, trimethyl amine quaternized	51838-31-4	1
Polyquaternium 15	35429-19-7	1
Resin coated cellulose	Proprietary	1
Silicon dioxide (crystalline)	60676-86-0	1
Silicon dioxide crystalline	60676-86-0	1
Sodium carbonate	497-19-8	1
Sodium perborate tetrahydrate	10486-00-7	1
Talc	Proprietary	1
Thiocyanic acid, sodium salt (1:1)	540-72-7	1
Trimethylamine, N-oxide	1184-78-7	1
2-Methylbutyrate	600-07-7	2
2-Propenoic acid, polymer with sodium phosphinate (1:1), sodium salt	71050-62-9	2
4,4`-Diaminodiphenyl sulfone	Proprietary	2
Adipic acid, dimethyl ester	Proprietary	2
Alcohols, Ethoxylated	Proprietary	2
bisHydrogenated Tallow Alkyl Dimethyl Salts With Bentonite	Proprietary	2
Bromic acid, sodium salt (1:1)	7789-38-0	2
Complex ester	Proprietary	2
Copolymer	Proprietary	2
decahydrate	Proprietary	2
Dimethyl glutarate	Proprietary	2
Ethylene-vinyl acetate copolymer	Proprietary	2
Gelatin	9000-70-8	2
Iron	7439-89-6	2
Magnesium iron silicate	1317-71-1	2
Magnesium silicate	1343-88-0	2
n-Beta-(aminoethyl)-gamma-amin opropyl trimethoxysilane	1760-24-3	2
Peroxidisulphate	Proprietary	2
Phenol / Formaldehyde Resin	900303-35-4	2
Propan-2-ol	Proprietary	2
Siloxanes and silicones, di-Me, polymers with Me silsesquioxanes	68037-74-1	2
Succinic acid, dimethyl ester	106-65-0	2
White Mineral Oil (Petroleum)	8042-47-5	2
2-Acrylamido-2-methylpropane sulfonate	38193-60-1	3
Aliphatic amide derivative	Proprietary	3
Aromatic acid derivative	Proprietary	3
Bis-quaternary Methacrylamide Monomer	Proprietary	3
Ceramic materials and wares	66402-68-4	3
Dodecylbenzene	Proprietary	3

Chemical Name	CASRN	No. Times Reported
Ethoxylated hexanol	68439-45-2	3
Hematite	1317-60-8	3
Iron oxide	1309-37-1	3
Maghemite	1309-38-2	3
Paraffinic solvent	Proprietary	3
Secondary alcohols, C12-14, ethoxylated	84133-50-6	3
Silanetriol, (3-aminopropyl)-, homopolymer	68400-07-7	3
Silanetriol, 1-(3-aminopropyl)-	58160-99-9	3
Sulfuric acid	Proprietary	3
Titanium oxide	13463-67-7	3
Alcohols, C10-16, ethoxylated	68002-97-1	4
Alcohols, C12-13, ethoxylated	66455-14-9	4
Formic Acid	64-18-6	4
Glycol	Proprietary	4
Neutralized Polycarboxylic Acid	Proprietary	4
Phosphonomethylated polyamine	68132-59-2	4
Sulfate	Proprietary	4
Bis-quaternary methacrylamide monomer	Proprietary	5
Glycol ether	Proprietary	5
Tall oil acid diethanolamide	68155-20-4	5
Thioglycolic Acid	68-11-1	5
Ammonium bifluoride	1341-49-7	6
Anitfoam	Proprietary	6
Biovert CF	Proprietary	6
Lactose	5989-81-1	6
Lecithins	8002-43-5	6
Modified cycloaliphatic amine adduct	Proprietary	6
Mullite	1302-93-8	6
Organic phoshonate	Proprietary	6
Organo amino silane	Proprietary	6
Poly (acrylamide-co-acrylic acid)	Proprietary	6
Salt	Proprietary	6
Siloxanes and silicones, dimethyl,	63148-52-7	6
Sorbitan Monooleate	Proprietary	6
2-Propen-1-aminium, N,N-dimethyl-N-2-propen-1-yl-, chloride (1:1), homopolymer	26062-79-3	7
2-Propenoic acid, homopolymer, sodium salt	9003-04-7	7
Alkyl Diamide	Proprietary	7
Ammonium sulfate	7783-20-2	7
Anionic Polymer	Proprietary	7
Cyclohexasiloxane, 2,2,4,4,6,6,8,8,10,10,12,12-dodecamethyl-	540-97-6	7
Cyclopentasiloxane, 2,2,4,4,6,6,8,8,10,10-decamethyl-	541-02-6	7
Diethanolamine	111-42-2	7

Chemical Name	CASRN	No. Times Reported
Lactose	63-42-3	7
Octamethylcyclotetrasiloxane	556-67-2	7
Oxylated alcohol	Proprietary	7
Polylactide resin	Proprietary	7
Polysiloxanes, di-Me	63148-62-9	7
Siloxanes and Silicones, di-Me	67762-90-7	7
Sulfurous acid, sodium salt (1:1)	7631-90-5	7
Tetramethyl ammonium chloride	75-57-0	7
Vinyl Copolymer	Proprietary	7
Butyl glycidyl ether	Proprietary	8
Butyl lactate	Proprietary	8
Caprylamidopropyl betaine	73772-46-0	8
Cocamidopropyl betaine	61789-40-0	8
Epoxy resin	Proprietary	8
Ethene, 1,1-dichloro-, homopolymer	9002-85-1	8
Ethylenediamine	107-15-3	8
oxide	Proprietary	8
Oxylated phenolic resin	Proprietary	8
Phosphate ester	Proprietary	8
Phosphonate salt	Proprietary	8
Phosphonic acid	Proprietary	8
Phosphoric acid salt	7632-05-5	8
Polyacrylate	Proprietary	8
Polyquaternary amine salt	Proprietary	8
Potassium bicarbonate	298-14-6	8
Sodium sulfite	7757-83-7	8
Water brine	Water NOS	8
Oxyalkylated alkyl alcohol (1)	Proprietary	9
Sodium thiosulfate	7772-98-7	9
Alcohols, C11 linear, ethoxylated	34398-01-1	10
Alcohols, C9-C11, ethoxylated	68439-46-3	10
Amine derivative	Proprietary	10
Cristobalite proppant	14464-46-1	10
Dodecylbenzene	123-01-3	10
Dodecylbenzene sulfonic acid	27176-87-0	10
Ethoxylated alcohol	Proprietary	10
Ethylbenzene	100-41-4	10
Linear/branched alcohol ethoxylate (11eo)	127036-24-2	10
Propanol, 1(or 2)-(2-methoxymethylethoxy)-	34590-94-8	10

Table 2.A-6. Chemical additives that are used in median quantities greater than 200 kg per hydraulic fracturing treatment. This table excludes base fluids (e.g., water, brine, saline solutions).

Chemical Name	CASRN	Chemical Mass Used Median (kg treatment^{-1})	95% of the Values are Below this Number (kg treatment^{-1})
Crystalline silica quartz proppant	14808-60-7	91,527.3	340,777.4
Magnesium silicate	1343-88-0	90,192.8	126,417.0
Ceramic materials and wares	66402-68-4	68,038.6	120,292.3
Mullite	1302-93-8	65,437.6	173,665.0
Resin coated cellulose	Proprietary	42,955.1	42,955.1
Silicon dioxide (crystalline)	60676-86-0	33,757.6	33,757.6
Magnesium iron silicate	1317-71-1	15,032.2	21,069.5
Silicon dioxide crystalline	60676-86-0	11,409.2	11,409.2
Kyanite	1302-76-7	8,887.9	94,521.3
Organic phoshonate	Proprietary	7,686.6	76,005.0
Alkanes / Alkenes	Proprietary	5,802.8	16,750.6
Hydrochloric acid	7647-01-0	4,868.0	24,933.4
Aluminum oxide	1344-28-1	4,494.7	82,791.4
Petroleum Distillate Blend	Proprietary	4,235.9	5,072.0
Cristobalite proppant	14464-46-1	4,139.6	40,862.3
Monoethanolamine	141-43-5	3,661.9	6,270.2
Biovert CF	Proprietary	3,102.4	4,765.3
Sodium carbonate	497-19-8	2,542.4	2,542.4
Lactose	63-42-3	2,002.3	2,268.3
GS-1L	Proprietary	1,650.2	1,650.2
Phenol, polymer with formaldehyde	9003-35-4	1,583.0	11,173.9
Alfa-Alumina	Proprietary	1,499.7	1,499.7
2-Acrylamido-2-methylpropane sulfonate	38193-60-1	1,317.5	1,600.6
Naphtha, hydrotreated heavy	64742-48-9	1,250.2	1,250.2
Potassium carbonate	584-08-7	1,208.7	6,487.1
Mixture of Surfactants	Proprietary	1,135.5	2,914.9
Sodium bicarbonate	144-55-8	1,066.7	5,792.1
Hydrofluoric acid	7664-39-3	1,022.2	8,996.0
Glyoxal	107-22-2	1,016.1	2,707.9
Polyquaternary amine salt	Proprietary	955.6	10,279.5
Unknown	Proprietary	876.3	889.6
Ethylbenzene	100-41-4	768.8	1,888.9
2-Propenoic acid, ammonium salt (1:1), polymer with 2-propenamide	26100-47-0	735.7	735.7
Carbohydrate polymer	Proprietary	660.3	2,676.9
Boric acid, dipotassium salt	1332-77-0	660.0	1,979.1

Chemical Name	CASRN	Chemical Mass Used Median (kg treatment^{-1})	95% of the Values are Below this Number (kg treatment^{-1})
Disodium octaborate	12008-41-2	627.9	1,569.9
Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-	9016-45-9	600.3	2,244.4
Guar gum	9000-30-0	589.2	4,702.8
Carbohydrates	Proprietary	553.6	4,065.3
Monoethanolamine borate (1:x)	26038-87-9	497.6	1,971.7
Acyclic hydrocarbon blend	Proprietary	453.6	2,882.6
Hematite	1317-60-8	449.5	674.2
Cocamidopropyl betaine	61789-40-0	438.9	947.8
Borate salts	Proprietary	365.8	670.2
Ammonium salt	Proprietary	349.2	2,919.2
D-glucitol	50-70-4	338.6	902.8
1-Methoxy-2-hydroxypropane	107-98-2	330.7	330.7
Oxyalkylated alcohol (2)	Proprietary	318.9	1,513.0
Aliphatic polyol	Proprietary	314.1	965.3
Methanol	67-56-1	276.1	1,293.7
Ammonium Chloride	12125-02-9	272.6	27,407.6
Distillates, petroleum, hydrotreated light paraffinic	64742-55-8	269.8	1,623.5
Ethoxylated nonylphenol	Proprietary	269.3	793.8
Isopropanol	67-63-0	267.8	975.9
Hydrotreated Light Petroleum Distillate	64742-47-8	267.2	1,867.6
Choline chloride	67-48-1	266.4	1,472.5
Formic Acid	64-18-6	264.9	2,493.4
FRW-16A	Proprietary	248.2	877.7
Citrus Terpenes	94266-47-4	245.2	245.2
Oxyakylated Amine Quat	Proprietary	238.9	881.0
2-Propen-1-aminium, N,N-dimethyl-N-2-propen-1-yl-, chloride (1:1), homopolymer	26062-79-3	238.0	405.7
Sodium thiosulfate	7772-98-7	229.8	445.2
Citric acid	77-92-9	228.9	646.9
Hematite	Proprietary	225.1	225.1
Polylactide resin	Proprietary	221.6	448.5
Ammonium bifluoride	1341-49-7	217.3	837.8
Complex ester	Proprietary	214.5	408.6
Triethanolamine	102-71-6	212.2	647.1
Glassy calcium magnesium phosphate	65997-17-3	204.5	215.9

Table 2.A-7. Most aquatically toxic (United Nations Globally Harmonized System of Classification and Labelling of Chemicals (GHS) Categories 1 or 2) chemicals used in well stimulation in California.

Chemical Name	CASRN	Acute Aquatic Daphnia Magna GHS Category	Acute Aquatic Fathead Minnow GHS Category	Acute Aquatic Trout GHS Category
1,2,4-Trimethylbenzene	95-63-6	2	2	
1,3,5-Trimethylbenzene	108-67-8	2		
2-Propenoic acid, ammonium salt (1:1), polymer with 2-propenamide	26100-47-0	1		
2,2-dibromo-3-nitrilopropionamide	10222-01-2	1	1	1
2-Mercaptoethyl alcohol	60-24-2	2		
2-Methyl-3(2H)-isothiazolone	2682-20-4	1		1
5-Chloro-2-methyl-3(2H)-isothiazolone	26172-55-4	1		1
Alcohols, C10-16, ethoxylated	68002-97-1	1		
Alcohols, C11 linear, ethoxylated	34398-01-1	2	2	
Alcohols, C12-13, ethoxylated	66455-14-9	1	1	
Alcohols, C9-C11, ethoxylated	68439-46-3	2	2	
Alkyl dimethylbenzyl ammonium chloride	68424-85-1	1	1	1
Ammonium chloride	12125-02-9	6	2	6
Benzyl chloride	100-44-7		2	
Butyl glycidyl ether	2426-08-6	2		
Chlorous acid, sodium salt (1:1)	7758-19-2	1		
Cocamidopropyl betaine	61789-40-0	2		
Dodecylbenzene sulfonic acid	27176-87-0	2		2
Ethaneperoxoic acid	79-21-0	2		
Ethoxylated C14-15 alcohols	68951-67-7	1	1	1
Ethoxylated hexanol	68439-45-2	2		2
Ethylbenzene	100-41-4	2	2	2
Ethylenediamine	107-15-3	2	6	
Glutaraldehyde	111-30-8	1	2	2
Hydrochloric acid	7647-01-0	1		2
Hydrogen peroxide	7722-84-1	2	3	3
Hydrotreated light petroleum distillate	64742-47-8		3	2
Isopropylbenzene	98-82-8	3	2	2
Isotridecanol, ethoxylated	9043-30-5	2		
Naphthalene	91-20-3	1	1	1

Chemical Name	CASRN	Acute Aquatic Daphnia Magna GHS Category	Acute Aquatic Fathead Minnow GHS Category	Acute Aquatic Trout GHS Category
Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-	9016-45-9	2		2
Propargyl alcohol	107-19-7		2	
Quaternary ammonium chloride, benzylcoco alkyldimethyl, chlorides	61789-71-7	1		
Sodium perborate tetrahydrate	10486-00-7	2		
Solvent naphtha, petroleum, heavy arom.	64742-94-5	1	3	2
Solvent naphtha, petroleum, light arom.	64742-95-6	2		2
Xylenes	1330-20-7		3	2

Table 2.A-8. Final list of priority compounds based on toxicity and mass used. Chemicals are ranked by the United Nations Globally Harmonized System of Classification and Labelling of Chemicals (GHS) based upon their LC_{50} or EC_{50} values. In the GHS system, lower numbers indicate higher toxicity, with a designation of "1" indicating the most toxic compounds. Tox code is the lowest (most toxic) designation from acute aquatic toxicity as described in Tables A.2-3 and A.2-7 and Figure 2.B-1. Mass of chemical used per well stimulation treatment is from Table A.2-1 and A.2-6.

Chemical Name	CASRN	Median Chemical Mass Used (kg treatment^{-1})	Tox Code (lowest GHS score in any aquatic toxicological category)
Hydrochloric acid	7647-01-0	4,868	1
2-Propenoic acid, ammonium salt (1:1), polymer with 2-propenamide	26100-47-0	736	1
Alcohols, C10-16, ethoxylated	68002-97-1	182	1
Ethoxylated C14-15 alcohols	68951-67-7	135	1
Glutaraldehyde	111-30-8	99	1
Chlorous acid, sodium salt (1:1)	7758-19-2	96	1
Alkyl dimethylbenzyl ammonium chloride	68424-85-1	29	1
Quaternary ammonium chloride, benzylcoco alkyldimethyl, chlorides	61789-71-7	25	1
DBNPA (2,2-dibromo-3-nitrilopropionamide)	10222-01-2	22	1
Solvent naphtha, petroleum, heavy arom.	64742-94-5	10	1
Alcohols, C12-13, ethoxylated	66455-14-9	2	1
5-Chloro-2-methyl-3(2H)-isothiazolone	26172-55-4	1	1
Naphthalene	91-20-3	1	1
2-Methyl-3(2H)-isothiazolone	2682-20-4	< 1	1
Ethylbenzene	100-41-4	769	2
Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-	9016-45-9	600	2
Cocamidopropyl betaine	61789-40-0	439	2
Ammonium Chloride	12125-02-9	273	2
Hydrotreated Light Petroleum Distillate	64742-47-8	267	2
Isotridecanol, ethoxylated	9043-30-5	44	2
Ethaneperoxoic acid	79-21-0	31	2
Ethoxylated hexanol	68439-45-2	15	2
Dodecylbenzene sulfonic acid	27176-87-0	14	2
Propargyl alcohol	107-19-7	8	2
Alcohols, C11 linear, ethoxylated	34398-01-1	4	2
1,2,4-Trimethylbenzene	95-63-6	3	2
Solvent naphtha, petroleum, light arom.	64742-95-6	3	2
Alcohols, C9-C11, ethoxylated	68439-46-3	2	2
Benzyl Chloride	100-44-7	2	2
Hydrogen peroxide	7722-84-1	1	2

Chemical Name	CASRN	Median Chemical Mass Used (kg treatment^{-1})	Tox Code (lowest GHS score in any aquatic toxicological category)
1,3,5-Trimethylbenzene	108-67-8	< 1	2
Isopropylbenzene	98-82-8	< 1	2
Xylenes	1330-20-7	< 1	2
2-Mercaptoethyl Alcohol	60-24-2		2
Butyl glycidyl ether	2426-08-6		2
Ethylenediamine	107-15-3		2
Sodium perborate tetrahydrate	10486-00-7		2
Monoethanolamine	141-43-5	3,662	3
Guar gum	9000-30-0	589	3
Poly(oxy-1,2-ethanediyl), alpha-hexyl-omega-hydroxy	31726-34-8	141	3
Boric acid	10043-35-3	101	3
Diethanolamine	111-42-2	97	3
Ammonium sulfate	7783-20-2	72	3
Zirconium oxychloride	7699-43-6	70	3
Boron oxide	1303-86-2	53	3
Sodium hydroxide	1310-73-2	33	3
Potassium chloride	7447-40-7	32	3
Glycerol	56-81-5	27	3
Tetrasodium ethylenediaminetetraacetate	64-02-8	24	3
Thiocyanic acid, sodium salt (1:1)	540-72-7	24	3
Ammonium Persulfate	7727-54-0	23	3
Sulfurous acid, sodium salt (1:1)	7631-90-5	21	3
Tetrakis hydroxymethyl-phosphonium sulfate	55566-30-8	9	3
Bis(2-ethylhexyl) sodium sulfosuccinate	577-11-7	8	3
Calcium chloride	10043-52-4	5	3
Acrylamide	79-06-1	4	3
Formaldehyde	50-00-0	1	3
Trisodium nitrilotriacetate	5064-31-3	1	3
2-Ethylhexan-1-ol	104-76-7	< 1	3
Acetic Acid	64-19-7	< 1	3
Polysiloxanes, di-Me	63148-62-9	< 1	3
Thioglycolic Acid	68-11-1	< 1	3
Adipic acid, dimethyl ester	627-93-0		3
Dimethyl glutarate	1119-40-0		3

Table 2.A-9. Chemical additive identified by non-specific name and reported as trade secrets, confidential business information, or proprietary information in the FracFocus Chemical Disclosure Registry. These materials cannot be evaluated for hazard, risk, and environmental impact without more specific identification. Chemicals additives that are not identified by CASRN cannot be conclusively identified and cannot be fully evaluated.

Chemical Name	Information entered in place of CASRN	Number of entries recorded
Acyclic hydrocarbon blend	Trade Secret	23
Alcohols, Ethoxylated	Confidential	2
Alfa-Alumina	(No entry)	1
Aliphatic alcohol	Proprietary	1
Aliphatic amide derivative	Proprietary	3
Aliphatic co-polymer	Proprietary	21
Aliphatic polyol	Proprietary	21
Alkanes / Alkenes	Multiple	33
Alkyl Diamide	Trade Secret	7
Alkylalcohol ethoxylated	Proprietary	12
Alkylene Oxide Block Polymer	Trade Secret	1
Alpha-(4-nonylphenyl)-omega-hydr oxy-, branched	(No entry)	1
Amine derivative	Proprietary	10
Amine salts	Confidential	52
Amine salts	Confidential Business Information	6
Amine salts	Proprietary	6
Amino alkyl phosphonic acid	Proprietary	1
Amino alkyl phosphonic acid	Trade Secret	672
Ammonium salt	Confidential	26
Ammonium salt	Confidential Business	2
Ammonium salt	Proprietary	1
Anionic Polymer	Trade Secret	7
Anitfoam	Trade Secret	6
Aromatic acid derivative	Proprietary	3
Aromatic Aldehyde	Trade Secret	1
BC-3	(No entry)	6
BC-3	NA	12
BC-3	NA	10
BC-3	Proprietary	3
BC-3	Trade Secret	64
Biovert CF	Confidential	6
Bis(hydrogenated tallow alkyl) dimethyl,salts with bentonite compounds	(No entry)	1

Chemical Name	Information entered in place of CASRN	Number of entries recorded
bisHydrogenated Tallow Alkyl Dimethyl Salts With Bentonite	(No entry)	2
Bis-quaternary methacrylamide monomer	Confidential	5
Bis-quaternary Methacrylamide Monomer	Confidential Business Information	3
Borate salts	Confidential	15
Borate salts	Confidential Business Information	14
Borate salts	Proprietary	1
Carbohydrate polymer	Proprietary	21
Carbohydrates	Confidential	27
Carbohydrates	Confidential Business Information	33
Carbohydrates	Proprietary	1
Cationic polymer	Proprietary	18
ClaWeb	Confidential Business Information	5
ClaWeb	Proprietary	31
Complex ester	Trade Secret	2
Copolymer	Trade Secret	2
Crystalline silica quartz proppant	NA	1
Cured acrylic resin	Confidential Business Information	2
Cured acrylic resin	Proprietary	3
Cured acrylic resin	Trade Secret	53
Cured resin	Trade Secret	20
Cyclic Alkanes	Trade Secret	1
Decahydrate	(No entry)	2
Dioctyl sulfosuccinate sodium salt	Proprietary	12
Dodecylbenzene	Proprietary	3
EDTA/Copper chelate	Confidential	32
EDTA/Copper chelate	Confidential Business	2
EDTA/Copper chelate	Confidential Business Information	42
EDTA/Copper chelate	Proprietary	2
Enzyme G	NA	89
Enzyme G	NA	392
Epoxy resin	Confidential Business Information	8
Ether	Trade Secret	1
Ethoxylated	(No entry)	1

Chemical Name	Information entered in place of CASRN	Number of entries recorded
Ethoxylated alcohol	Proprietary	4
Ethoxylated alcohol	Trade Secret	6
Ethoxylated alkylphenol (1)	Trade Secret	1
Ethoxylated nonylphenol	Confidential	7
Ethoxylated nonylphenol	Confidential Business	3
Ethoxylated nonylphenol	Confidential Business Information	32
Ethylene-vinyl acetate copolymer	Trade Secret	2
Exyalkylated amine	Trade Secret	1
Fatty acid tall oil amide	Confidential	17
Fatty acids	Proprietary	2
Fatty acids	Trade Secret	18
Fatty acids, tall-oil	Confidential	1
FRW-16A	NA	2
FRW-16A	Proprietary	2
FRW-16A	Trade Secret	9
Glycol	Proprietary	3
Glycol	Trade Secret	1
Glycol ether	Confidential Business Information	2
Glycol ether	Proprietary	3
GS-1L	Trade Secret	1
Hematite	(No entry)	1
Hemicellulase enzyme	NA	89
Hemicellulase enzyme	NA	22
Inorganic mineral	Proprietary	11
Maghemite	(No entry)	1
Mixture of Surfactants	Trade Secret	62
Modified bentonite	Confidential	1
Modified cycloaliphatic amine adduct	Mixture	6
Neutralized Polycarboxylic Acid	Proprietary	4
Olefins	Confidential	4
Olefins	Proprietary	2
Olefins	Trade Secret	18
Organic phoshonate	Proprietary	6
Organic sulfur compound	Trade Secret	1
Organo amino silane	Confidential Business Information	6
oxide	(No entry)	8
Oxyakylated Amine Quat	Trade Secret	26

Chemical Name	Information entered in place of CASRN	Number of entries recorded
Oxyalkylated alcohol (1)	Proprietary	21
Oxyalkylated alcohol (2)	Proprietary	20
Oxyalkylated alkyl alcohol (1)	Proprietary	9
Oxyalkylated alkylphenol (1)	Trade Secret	24
Oxyalkylated alkylphenol (2)	Trade Secret	25
Oxyalkylated amine	Trade Secret	24
Oxyalkylated fatty acid	Trade Secret	1
Oxyalkylated phenolic resin	Confidential Business Information	12
Oxylated alcohol	Confidential	6
Oxylated alcohol	Confidential Business Information	1
Oxylated phenolic resin	Confidential	8
Paraffinic solvent	Confidential Business Information	3
Peroxidisulphate	(No entry)	2
Petroleum Distillate Blend	CBI	10
Petroleum Distillate Blend	Proprietary	111
Petroleum Distillate Blend	Trade Secret	30
Phosphate ester	Confidential Business Information	8
Phosphonate salt	Trade Secret	8
Phosphonic acid	Proprietary	8
Poly (acrylamide-co-acrylic acid)	Trade Secret	6
Poly(dimethylaminoethyl methacrylate dimethyl sulfate quat)	Proprietary	1
Polyacrylamide copolymer	Confidential	17
Polyacrylamide copolymer	Confidential Business	1
Polyacrylamide copolymer	Confidential Business Information	4
Polyacrylate	Trade Secret	8
Polylactide resin	Confidential	7
Polymer	Proprietary	26
Polyoxyalkylene	Trade Secret	25
Polyoxyalkylenes	Proprietary	2
Polyoxyalkylenes	Trade Secret	32
Polyquaternary amine salt	Confidential	5
Polyquaternary amine salt	Confidential Business Information	3
Propan-2-ol	Proprietary	2
Quaternary amine	Confidential	78

Chemical Name	Information entered in place of CASRN	Number of entries recorded
Quaternary amine	Confidential Business Information	17
Quaternary ammonium compounds	Confidential	9
Quaternary ammonium compounds	Proprietary	9
Quaternary ammonium compounds	Trade Secret	2
Resin coated cellulose	Proprietary	1
Salt	Trade Secret	6
Sorbitan Monooleate	Trade Secret	6
Sulfate	(No entry)	4
Sulfonate	Confidential	27
Sulfonate	Confidential Business Information	7
Sulfonate	Proprietary	2
Sulfuric acid	Proprietary	3
Surfactant mixture	CBI	12
Surfactant mixture	Confidential	88
Surfactant mixture	Confidential Business	1
Surfactant mixture	Confidential Business Information	3
Surfactant mixture	NA	1
Surfactant mixture	Proprietary	4
Surfactant mixture	Trade Secret	42
Talc	(No entry)	1
Unknown	(No entry)	5
Unknown	Confidential Business Information	9
Unknown	NA	5
Unknown	Trade Secret	1
Vinyl Copolymer	Trade Secret	7
Water base fluid	(No entry)	44
Water base fluid	NA	101
Water base fluid	Proprietary	1
Water brine	NA	8
Water KCL mix	(No entry)	5
Water KCL mix	NA	18
Water produced	(No entry)	19

Table 2.A-10. Chemicals used for hydraulic fracturing and matrix acidizing in California, as reported in DOGGR's Well Stimulation Treatment Disclosure Reports prior to May, 2015, that were not reported in voluntary disclosures to the FracFocus Chemical Disclosure Registry (Table 2.A-1). Well Stimulation Treatment Disclosure Reports are required within 60 days of cessation of well stimulation treatment under Senate Bill 4 (SB 4).

Chemical Name	CASRN	Reported as used in matrix acidizing	Reported as used in hydraulic fracturing
1-Eicosene	3452-07-1	Yes	Yes
Hydroxylamine hydrochloride	5470-11-1	Yes	No
Acetaldol	107-89-1	Yes	No
1-Tetradecene	1120-36-1	Yes	Yes
1-Octadecene	112-88-9	Yes	Yes
Ammonium fluoride	12125-01-8	Yes	Yes
Benzyldimethylammonium chloride	122-18-9	Yes	Yes
Lauryl hydroxysultaine	13197-76-7	Yes	Yes
Benzododecinium chloride	139-07-1	Yes	Yes
Miristalkonium chloride	139-08-2	Yes	Yes
Nitrilotriacetic acid	139-13-9	Yes	No
Fatty acids, C18-unsatd., dimers	61788-89-4	Yes	No
Amines, hydrogenated tallow alkyl, acetates	61790-59-8	Yes	Yes
1-Hexadecene	629-73-2	Yes	Yes
Benzoic acid	65-85-0	Yes	No
Poly(oxy-1,2-ethanediyl), alpha-(nonylphenyl)-omega-hydroxy-, branched, phosphates	68412-53-3	Yes	No
Benzenesulfonic acid, C10-16-alkyl derivs., compds. with 2-propanamine	68584-24-7	Yes	Yes
Benzenesulfonic acid, C10-16-alkyl derivs., compds. with triethanolamine	68584-25-8	Yes	Yes
Copper dichloride	7447-39-4	Yes	No
Ethylene oxide	75-21-8	Yes	Yes
Potassium iodide	7681-11-0	Yes	No
Nitrogen	7727-37-9	Yes	No
Calcium phosphate, tribasic	7758-87-4	Yes	Yes
Aluminum chloride	7784-13-6	Yes	No
1,3-Propanediaminium, 2-hydroxy-N,N,N,N′,N′-pentamethyl-N′-(3-((2-methyl-1-oxo-2-propenyl) amino)propyl)-, dichloride, homopolymer	86706-87-8	Yes	No
Acrylamide acrylate copolymer	9003-06-9	No	Yes
Triethanolamine zirconate	101033-44-7	No	Yes
Acrylonitrile	107-13-1	No	Yes
Toluene	108-88-3	No	Yes
Xanthan gum	11138-66-2	No	Yes
Triethylene glycol	112-27-6	No	Yes

Chemical Name	CASRN	Reported as used in matrix acidizing	Reported as used in hydraulic fracturing
Ulexite	1319-33-1	No	Yes
Diethylenetriaminepenta(methylenephosphonic) acid	15827-60-8	No	Yes
Xylenesulfonic acid	25321-41-9	No	Yes
Polypropylene glycol	25322-69-4	No	Yes
Food red 10	3734-67-6	No	Yes
Ethanol, 2-amino-, 1-acetate (1:1)	54300-24-2	No	Yes
Prolonium chloride	55636-09-4	No	Yes
Amines, dicoco alkylmethyl	61788-62-3	No	Yes
Ethoxylated castor oil	61791-12-6	No	Yes
Pontacyl carmine 2B	6625-46-3	No	Yes
Aziridine, homopolymer, ethoxylated	68130-99-4	No	Yes
Alcohols, C12-15 ethoxylated	68131-39-5	No	Yes
1,2-Ethanediamine, N1-(2-aminoethyl)-N2-(2-((2-aminoethyl)amino)ethyl)-, polymer with 2-methyloxirane and oxirane	68815-65-6	No	Yes
Poly(oxy-1,2-ethanediyl), alpha-(2,4,6-tris(1-phenylethyl)phenyl)-omega-hydroxy-	70559-25-0	No	Yes
Phosphonic acid, P,P',P'',P'''-(((phosphonomethyl) imino)bis(2,1-ethanediylnitrilobis(methylene))) tetrakis-, ammonium salt (1:?)	70714-66-8	No	Yes
n-Propanol	71-23-8	No	Yes
Aluminum	7429-90-5	No	Yes
Extract of walnut	84012-43-1	No	Yes
1,4-Dioxane-2,5-dione, 3,6-dimethyl-, (3R,6R)-, polymer with rel-(3R,6S)-3,6-dimethyl-1,4-dioxane-2,5-dione and (3S,6S)-3,6-dimethyl-1,4-dioxane-2,5-dione	9051-89-2	No	Yes
Amaranth Dye	915-67-3	No	Yes

Appendix 2.B

Figures for Section 2.4 Characterization of Well Stimulation Fluids

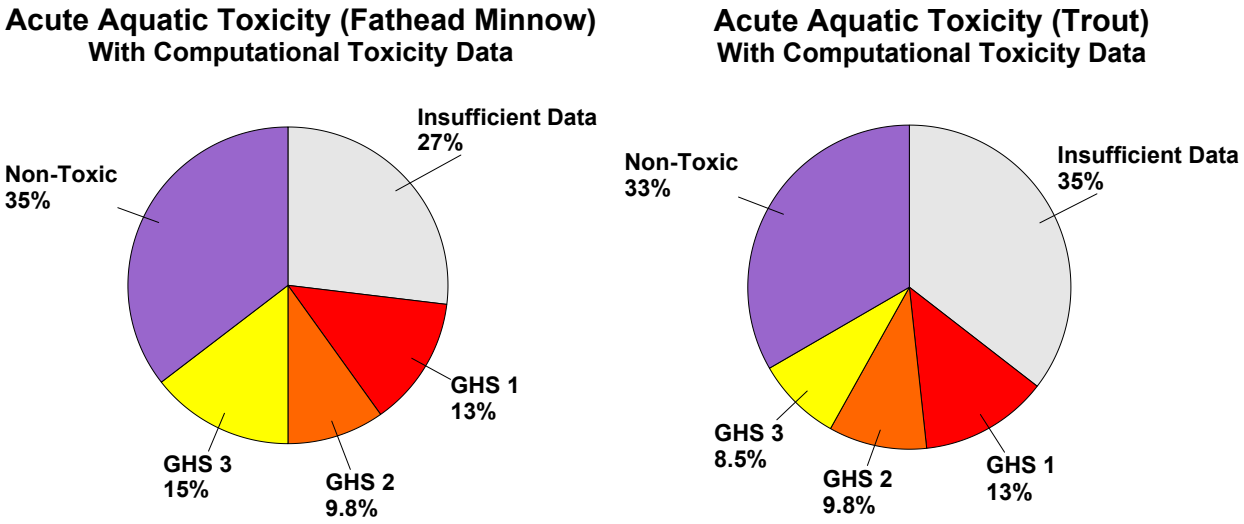

Figure 2.B-1. Computational data and experimental data combined for aquatic species. Chemical toxicity was categorized according to United Nations standards in the Globally Harmonized System of Classification and Labelling of Chemicals (GHS), which classifies acute toxicity for aquatic species on a scale of 1 to 3, with 3 being the least toxic. For pie charts containing both experimental and computational toxicity data, the experimental data was used as the value for that chemical in the creation of the pie chart. If only computational data was available, the computational value was used.

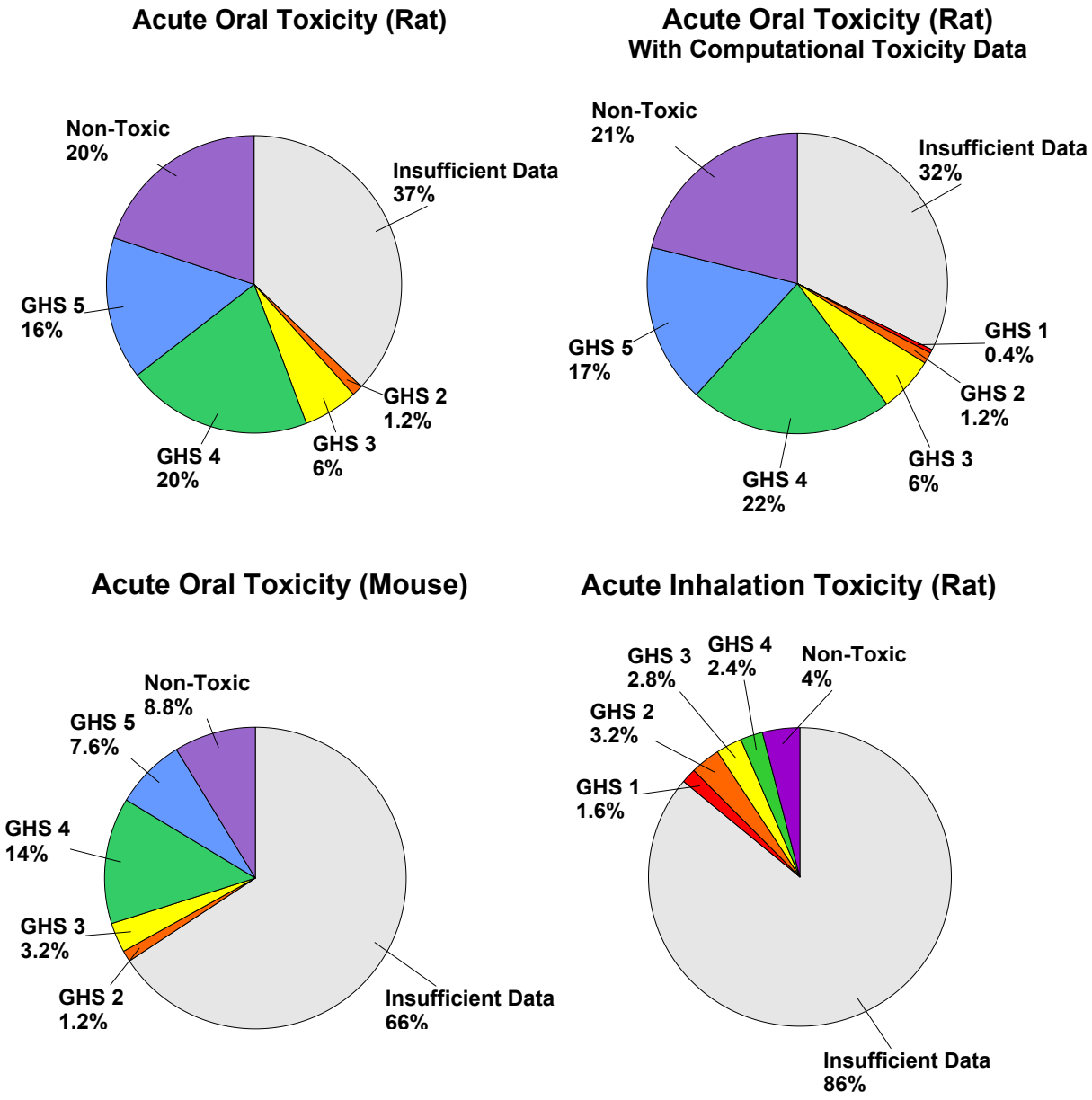

Figure 2.B-2. Acute mammalian toxicity. Chemical toxicity was categorized according to United Nations standards in the Globally Harmonized System of Classification and Labelling of Chemicals (GHS), which classifies acute toxicity for mammals on a scale of 1 to 5, with 5 being the least toxic. For pie charts containing both experimental and computational toxicity data, the experimental data was used as the value for that chemical in the creation of the pie chart. If only computational data was available, the computational value was used.

Appendix 2.C

Treatment of Production Water

Table 2.C-1. Treatment technology matrix for determining effectiveness of various water treatment technologies at removal of select constituents found in well stimulation fluids and expected in wastewaters from well stimulation operations and unconventional oil and gas wells.

Treatment Technology	Biocides	Breakers		Clay stabilizers	Corrosion inhibitors	Cross-linkers		Friction reducers	Gelling agents	Proppant	Scale inhibitors
		Ionic	Enzyme			Boron-based	Organic				
Physical											
Adsorptiont	V/P	no	no	no	yes	V/P	no	no	no	no	no
Air stripping	no	no	no	no	no	no	V/P	no	no	no	no
Centrifuge/Hydrocyclones	no	no	no	no	no	no	no	no	no	yes	no
Coagulation/Flocculation	V/P	V/P	V/P	no	V/P	no	V/P	V/P	V/P	no	V/P
Dissolved Air/Gas Floatation	no	no	no	no	no	no	V/P	no	no	no	no
Electrocoagulation	no	no	no	no	V/P	yes	yes	V/P	no	no	no
Evaporation	no	yes	V/P	no	no	yes	V/P	no	no	yes	V/P
Filtration	no	no	no	no	V/P	no	no	no	no	yes	no
Ion exchange	no	yes	no	yes	no	yes	no	no	no	no	V/P
Microfiltration (MF)/Ultrafiltration (UF)	no	no	no	no	NP	no	NP	NP	NP	yes	NP
Nanofiltration (NF)/Reverse Osmosis (RO)	NP	V/P	yes	yes	NP	yes	NP	NP	NP	NP	NP
Sedimentation	no	no	no	no	unknown	no	no	no	no	yes	V/P

Treatment Technology	Biocides	Breakers		Clay stabilizers	Corrosion inhibitors	Cross-linkers		Friction reducers	Gelling agents	Proppant	Scale inhibitors
		Ionic	Enzyme			Boron-based	Organic				
Chemical											
Advanced Chemical Oxidation	yes	no	yes	no	yes	no	yes	yes	yes	no	V/P
Conventional Chemical Oxidation	yes	no	yes	no	yes	no	yes	yes	yes	no	V/P
Lime and soda ash softening	no	V/P	V/P	no	yes	V/P	V/P	V/P	V/P	no	no
UV irradiation	no	no	no	no	no	no	no	no	no	no	no
Biological											
Biological Treatment Systems	V/P	V/P	yes	V/P	yes	V/P	yes	yes	yes	NP	V/P

NP (Not Practical) - cannot be implemented independently, component removed by another process with less expense

V/P (Various/Partial) – various or partial removal of component

Yes - proven, practical, or in use

No - demonstrated fundamentally incompatible with process (e.g., solute not removed in process for particle removal)

Unknown - insufficient information, not proven

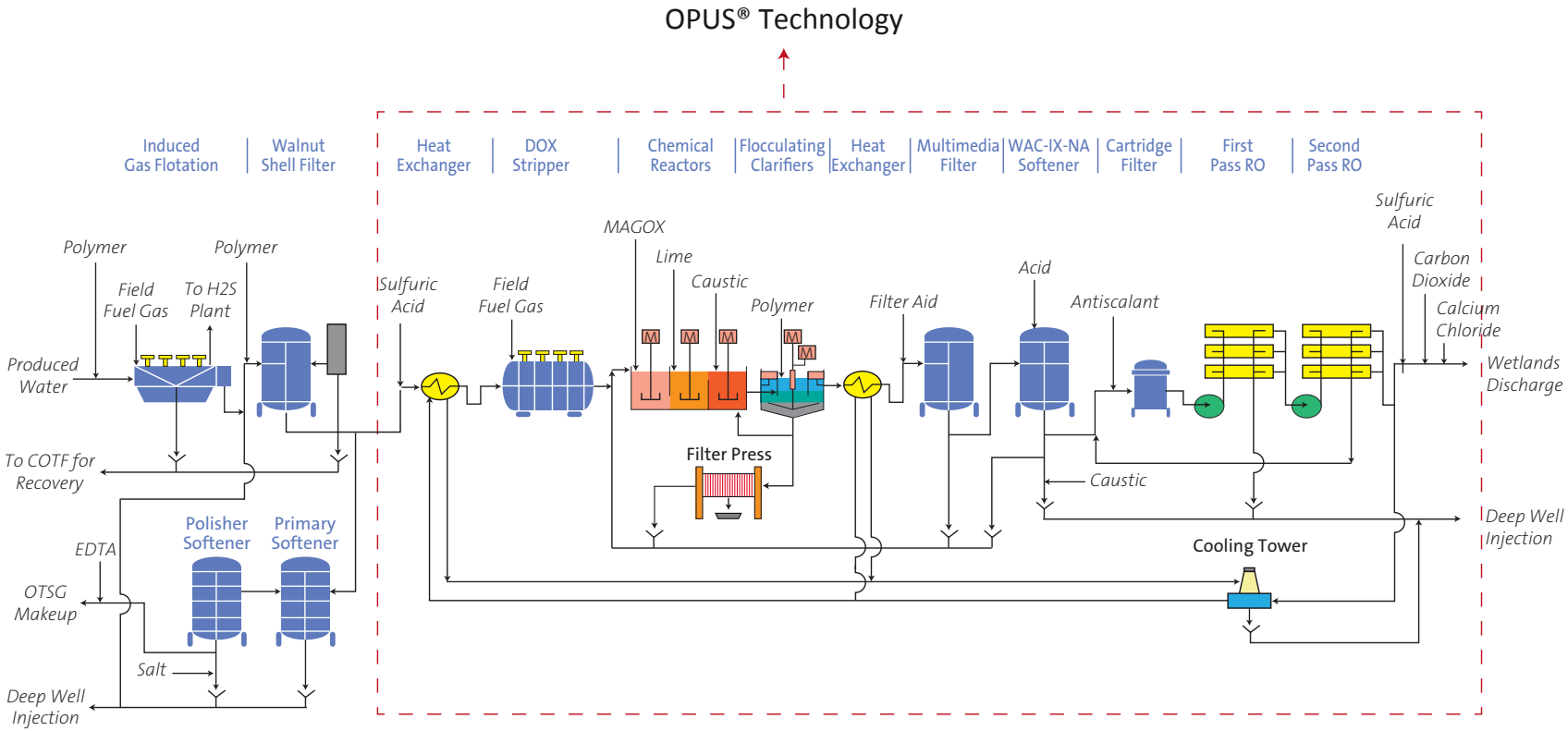

Figure 2.C-1. ***Flow Schematic of the San Ardo Oil Field Water Management Facility (Veolia Water, 2012). Produced water first undergoes induced gas flotation and walnut shell filtration. A portion of the flow is diverted through primary and polishing softeners before being reused in once-through steam generation. The remainder of the flow is treated using heat exchangers, DOX strippers, coagulation and flocculation, clarifiers, multimedia filters, weak acid cation ion exchange sodium (WA-IX-NA) softening, and cartridge filters followed by a two-pass RO system and pH adjustment for discharge into post-treatment free water surface wetlands and eventually to percolation basins for groundwater recharge and eventual agricultural use.***

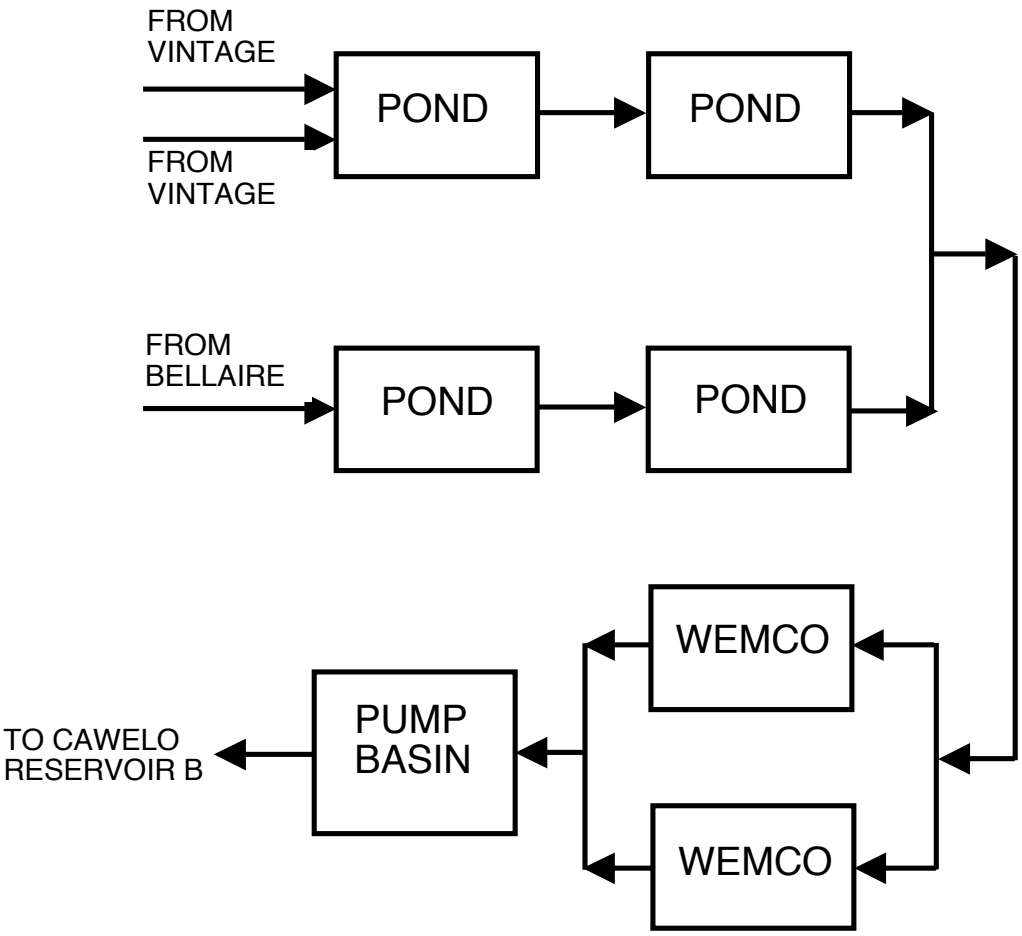

Figure 2.C-2. Flow Schematic of the Valley Water Management Company's Kern Front No. 2 Treatment Facility (CVRWQCB, 2012). Produced water is treated using four unlined ponds for gravity separation followed by air flotation units with coagulants and mechanical agitation (WEMCO®) before being discharged for eventual blending with fresh water in Cawelo Water District's (CWD) Reservoir B for agricultural use.

Appendix 2.D

Review of Technologies Available for Ensuring Well Integrity

2.D.1. Well Drilling, Construction, Stimulation, and Monitoring Methods

Well stimulation has been evaluated in this report relative to possible environmental and human health impacts. The impacts of subsurface injection of stimulation chemicals and materials, as well as pressure-driven fracturing, depend on how the stimulations are conducted. This section focuses on ways to conduct well stimulation to potentially reduce impacts related to the subsurface aspects of well stimulation, in particular the potential loss of containment of subsurface fluids and contamination of groundwater or the surface environment from injected or mobilized fluids. Other potential impacts from well stimulation are related to surface activities (e.g., surface spills, atmospheric emissions from surface equipment, noise, etc.) and are discussed in other sections of this report.

Loss of containment means that the injected stimulation fluids or mobilized resident fluids are able to migrate into subsurface resources (e.g., potable groundwater) or to the ground surface. Loss of containment is primarily a concern for hydraulic or acid fracturing and of less concern for matrix acidizing. This is because hydraulic fracturing is performed at high pressures that cause fracturing as compared with lower-pressure injections (below fracture pressure) of acid for matrix acidizing. Furthermore, hydraulic fracturing typically uses larger volumes of injected fluids than matrix acidizing (Table 2.3-1). High-pressure injections associated with hydraulic fracturing result in more permeable fracture pathways that can lead directly to loss of containment if the fractures extend far enough vertically from the injection point, or could result in fracture connections to existing features (e.g., faults, offset wells) that act as pathways to groundwater or the ground surface.

2.D.2. Loss of Containment from Out-of Zone Fracturing

The potential for fracturing to extend into groundwater resources or to the ground surface is strongly affected by the depth of the reservoir receiving the well stimulation treatment. Documentation about the maximum vertical extent of fractures for high-volume hydraulic fracturing of source-rock shale reservoirs indicate that the maximum vertical extent that has been observed is 588 m (1,930 ft) (Davies et al., 2012). Therefore, stimulations performed more than this distance below potable groundwater or the ground surface have little chance of loss of containment via induced fractures.

Fracturing in shallower reservoirs may potentially result in fractures that directly cause loss of containment. The principal ways to avoid this are careful characterization of the geologic environment, including stratigraphic layering of the hydrological and

geomechanical properties of the layers. This information is then used to develop fracturing models to predict the extent of hydraulic fracturing, referred to as the axial dimensional stimulation area, or ADSA, in new regulations. In addition to careful fracture design, geophysical and hydrological measurements taken during the hydraulic fracture treatment can be used to identify the actual extent of fracture propagation. These types of monitoring methods are discussed in Section 2.6.

2.D.2.1. Loss of Containment from Fracture Connection with Natural or Offset Anthropogenic Structures

Another way in which hydraulic fracturing can lead to a loss of containment is through induced fractures that connect with high-permeability structures. Such structures may be offset wells that are not properly sealed, or fracture zones or faults that are connected to groundwater or the ground surface. Resident or injected fluids may then flow through these structures to groundwater or to the ground surface. Clearly, to avoid problems with leakage along these types of structures, careful site characterization of the system is necessary to identify any wells or geologic features within the area expected to be affected by the well stimulation treatment. Shultz et al. (2014) identify well integrity, undocumented wells, subsurface integrity and geologic barriers, and shallow caprock systems as areas of concern regarding subsurface containment for general oil and gas production operations.

General reservoir characterization techniques (Balasubramanian et al., 2012) can be useful to inform containment analyses. The use of geophysical methods has been shown to be useful for the detection of some types of subsurface geologic hazards (Laake, 2014). Methods to ensure well integrity include wellhead and safety valve integrity testing, emergency shutdown systems testing, pressure monitoring and inspection of well casing annuli, temperature surveys to detect flow behind casing, and casing corrosion logging (Al Khamis et al., 2014). Several concepts concerning site characterization investigated for geologic CO_2 sequestration (Birkholzer and Tsang, 2008) are potentially relevant to characterization of petroleum systems.

Characterization should also identify basic hydrologic conditions that impact the potential communication between the reservoir rocks and the overlying freshwater systems. In particular, hydraulic gradients between the shallow and deep intervals should be measured along with the depths of the petroleum reservoir and groundwater aquifer. These gradients may be increased not only by pressure increases in the petroleum-bearing horizon by hydraulic fracturing fluid pressure, but also by fresh groundwater production. On the other hand, longer-term petroleum production may result in net declines in the deep fluid pressures, reducing the potential for upward migration of contaminants.

Both operating and abandoned offset wells within the zone of pressurization from a hydraulic fracture treatment represent potential leakage pathways to groundwater resources and the surface. Therefore, these wells must be considered during a site

characterization prior to conducting hydraulic fracturing. Characterization should include geographic location, depth of penetration, age, and status of offset wells. Well records should be reviewed for the type of casing, completion, and cement types used, and their location in the borehole (Michael et al., 2006). In some cases, abandoned wells may also be "lost" in the sense that there is no documentation of their existence. Surface geophysical methods (metal detection and magnetometry) may be of use for locating unknown abandoned wells (Ohio EPA, 2008). Operating offset wells should be remediated if the existing completion is not adequate to isolate all hydrocarbon and freshwater zones from the anticipated pressures. Operating offset wells should also be shut-in during stimulation (Dussault and Jackson, 2013). Abandoned wells that have not been properly plugged (or whose abandonment status is not known) should be re-entered and properly plugged. Offset wells should be monitored during stimulation for any signs of leakage.

The problem of proximal leakage pathways caused by natural or anthropogenic structures has been identified in the scientific literature, although the currently available information is insufficient to quantify this problem or make definitive recommendations. Dussault and Jackson (2013) identify hydraulic fracturing near structurally deformed regions containing faults or fracture zones as a potential avenue for loss of containment. However, it appears that specific stand-off requirements have not been formulated. Dussault and Jackson (2013) suggest that additional research is needed to better understand the problem, but estimate that the zone of influence around the stimulated well may be on the order of a few hundred meters. King (2012) discusses problems associated with fracture intersections with other wells as potential leakage pathways. The susceptibility of an offset well intercepted by a fracture resulting in leakage is dependent on the well design, casing depths, cement properties and placement, production and maintenance history, and other factors (API, 2014). Older abandoned wells are often more problematic than wells currently in use for the oil field (Bachu and Valencia, 2014).

2.D.2.2. Loss of Containment from Leakage along Stimulated Well

Leakage along the well receiving the well stimulation treatment could cause a loss of containment. This is an issue of proper well construction and testing, discussed in Section 2.6, to ensure zonal isolation. As before, this is more of a concern for hydraulic fracturing than matrix acidizing, because the hydraulic fracturing treatment potentially puts greater stress on the well casing and cement than matrix acidizing. The potential for well casing and cement damage from well stimulation treatments is reduced if the injection is conducted through well tubing instead of directly down casing. The use of tubing for treatment appears to be more prevalent for matrix acidizing than hydraulic fracturing, but may be used for either, depending on specific circumstances. The reason that hydraulic fracturing is more often conducted directly through the casing is because hydraulic fracturing treatment pumping rates are generally higher than for matrix acidizing. Injection through casing provides less resistance and requires lower pumping pressures than performing the injection through smaller-diameter tubing. Leakage along a well may occur in any case, regardless of how stimulation is conducted or even if no stimulation is conducted, because of inadequate well construction, but falls outside the purview of this report.

2.D.3. Well Drilling and Construction

As discussed in Section 2.6, one of the ways in which a well stimulation treatment may lead to loss of containment is because of inadequate well construction. Well drilling plays a role in well construction, so it is included in this discussion. The key issue is the isolation of fluid movement up (or down) the well inside the casing, or tubing internal to the casing. Fluid movement along the outside of the casing or fluid exchange between inside and outside the casing, except in zones where such exchange is intended, should be prevented by the casing and cement that bonds the casing to the formation. This aspect of well construction is termed *zonal isolation*.

2.D.3.1. Well Drilling

There are several factors to be considered as part of well drilling and well construction that are important for achieving zonal isolation (API, 2010). The first step to achieve good zonal isolation is the drilling of a smooth-walled, in-gauge borehole. Washouts and other borehole geometry irregularities lead to problems with casing centralization in the borehole and effective displacement of the drilling mud by cement. A key factor for optimal drilling is the density of the drilling fluid, typically known as drilling mud. The density affects the mud pressure which must be kept within bounds set by the formation fluid pressure, wellbore collapse pressure, and the fracture pressure, known as the mud weight window (Cook et al., 2012). If the mud pressure drops below the formation fluid pressure, formation fluids will enter the well, and well control can be lost. In some instances, mechanical integrity of the wellbore can lead to a higher wellbore collapse pressure than the formation fluid pressure, requiring higher mud pressure. If mud pressure is below the wellbore collapse pressure, the borehole can deform and cave into the borehole. If mud pressure is above the fracture pressure, however, the formation will fracture, and mud may flow into the fractures at high rates, resulting in lost circulation of the mud.

Another issue for drilling is the chemical compatibility of the mud with reactive formation rock types. Shales are the main problem in terms of chemical compatibility and present many drilling problems, including hole collapse, tight hole, stuck pipe, poor hole cleaning, hole enlargement, plastic flow, fracturing, lost circulation, and loss of well control (Lal, 1999). There are three distinct categories of drilling fluids: water-based muds, oil-based muds, and gas (also aerated muds, foams, and mists). The typical drilling fluid is a water-based mud; usage of oil-based mud or gas is much less common (Khodja et al., 2010). The main method to improve shale stability relative to drilling mud is to inhibit drilling fluid entry into the shale. This is done by (a) increasing drilling fluid viscosity; (b) reducing the shale permeability; and (c) increasing the osmotic pressure of the drilling mud (Khodja et al., 2010). Increasing the drilling fluid viscosity and reducing shale permeability at the borehole interface limits the interaction of the drilling fluid with the shale. Various additives are used to increase drilling fluid viscosity, such as methylglucoside, (poly-) glycerols, and (poly-)glycols (van Oort, 2003); however, viscosity increases are limited by system pressure limits and the pressure losses incurred when circulating the drilling fluid

(Khodja et al., 2010). Reductions in shale permeability may be achieved by using silicate-based drilling fluids that block shale pores with silicate precipitates and silicate gels (van Oort, 2003). Asphaltenes, gilsonites, and graphites are useful additives for blocking microcracks in shales (van Oort, 2003). Shale dehydration also promotes stability, which can be achieved through the osmotic pressure of the drilling mud by adding potassium chloride, sodium chloride, and other electrolytes (Lal, 1999). The type of electrolyte used depends on the mineralogical character of the shale.

In addition to the various properties of drilling fluids that can be optimized to produce a quality hole geometry, there are additional factors including the borehole inclination with respect to the principal stress directions, drillstring vibration, and mud circulation rate (McLellan, 1996). Also, the rate of penetration of the drilling can be a factor; if the rate of penetration is too great, cuttings may not be effectively removed, raising the equivalent mud density that can lead to wellbore instability (Aldred et al., 1999).

A key to avoiding well instability problems is adequate planning prior to drilling. This involves the development of a mechanical earth model that can be used to test drilling strategies (Aldred et al., 1999). This involves collecting or estimating model inputs such as rock geomechanical properties, *in situ* stresses, and pore pressures. The effects of mud composition on shale properties are also important to investigate to help inform the model about changes in shale properties with exposure to drilling muds. During drilling, it is important to monitor the cuttings; blocky solids are a sign of borehole caving. Also, excessive vibration in the drill string is an indication of borehole stability problems. Adjustments to the weight on bit, mud density, bit rotation rate, and mud circulation rate may be needed. If necessary, case the well at shallower depth than planned.

Alternative drilling methods, called “casing drilling” and “liner drilling,” have been found to limit adverse effects of wellbore instability and produce high-quality borehole geometry (Dawson et al., 2010; Fontenot et al., 2005; Moellendick and Karimi, 2011; Rosenberg and Galla, 2012). In this method, larger-diameter casing (or liner) pipe is used instead of the traditional drill pipe to hold the drill bit and other components of the bottom-hole assembly during drilling operations. Once the borehole has been drilled, the casing pipe is already in place, so the operations of pulling the drill pipe and installing the casing pipe are eliminated. The method improves borehole stability by reducing the number of pipe trips that can destabilize borehole walls and by reducing the annulus gap between the pipe used for drilling and the borehole wall, which facilitates cuttings transport. Furthermore, continuous trowelling of the wellbore wall by the casing improves borehole strength and reduces drilling fluid losses to the formation.

2.D.3.2. Well Construction

Following drilling, a well is constructed by placing a steel pipe called “casing” in the well, and then cementing the annulus between the casing and the formation. Well construction also involves the installation of the interface between the well casing and surface equipment, which takes the form of piping, connectors, valves, and pressure

gauges connected to the casing called a "Christmas tree." The casing and cement hold the well open during production operations and control the fluid flow pathway along the well to be exclusively inside the casing. Well construction is a critical step for zonal isolation, because if flow along the well is not controlled, unwanted fluid exchange and contamination will occur between the target reservoir, useable groundwater, and the ground surface.

Casing and cementing a well is done in stages, in which a series of casing pipes are installed and cemented along the length of the borehole as it is being drilled. The key steps for zonal isolation are the proper selection and placement of casing pipe followed by the displacement of the drilling mud by cement to bond the formation to the casing. Wells are secured at discrete intervals as the borehole is being drilled by installing a steel pipe (casing) with diameter slightly smaller than the borehole diameter. The casing is then fixed in place by filling the annulus between the pipe and the borehole wall with cement. The first casing is called the conductor casing, which extends at most only a few tens of meters into the ground to help hold up the unconsolidated surficial materials. Each subsequent casing string nests inside the previous casing string, with a small annular space between the casings that may be filled with cement. The surface casing follows the conductor casing and extends below freshwater aquifers. Subsequent intermediate and production casing strings or liners are used as needed to reach the target depth.

Casing pipe comes in segments that have to be joined into a continuous casing string as it is lowered into the well. The casing is threaded on each end and uses a coupling to hold the casing segments together. The casing is subject to hydraulic and mechanical stress, including axial tension caused by its own weight, as well as dynamic stresses caused by installation and operational activities, external fluid pressures from the formation during cementing operations that can cause collapse of the casing, and internal fluid pressure during drilling and operations that can lead to burst failure. Thermal stresses are also present, and formation induced stresses of creep and seismic movement must be accounted for in the design. Therefore, casing must meet strict requirements for compression, tension, collapse, and burst resistance; these requirements need to be taken into account when selecting casing type and size (Lyons and Plisga, 2005). For systems that will be used for hydraulic fracturing, the high levels of fluid pressure imposed also need to be taken into account for casing design (API, 2009). Casing pipe specifications are provided in ISO 11960/API Specification 5CT – *Specification for Casing and Tubing*. The casing and coupling thread specifications are provided in API Specification 5B, *Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads*.

Another factor that is important for displacement of drilling fluids by cement is centralization of the casing in the hole. Centralization is needed to ensure displacement of drilling fluids all around the casing. Cement will tend to flow along the wide side of the annulus if not centralized, resulting in poor displacement of drilling fluid and poor cementing in the narrower annular regions. This becomes more problematic for deviated boreholes. A casing centralizer consists of a set of mechanical "arms" that are attached to the casing and extend outward from the casing to ensure standoff from the borehole wall.

Different types of centralizers are used for vertical and deviated boreholes. Specifications are given in:

- ISO 10427-1/API Specification 10D – *Specification for Bow-Spring Casing Centralizers*
- ISO 10427-2/API Specification 10D-2 – *Recommended Practice for Centralizer Placement and Stop Collar Testing*.

Different types of cements are used depending on conditions of depth, temperature, pressure, and chemical environment (Lyons and Plisga, 2005). Temperature is perhaps the most important environmental condition that affects cement slurry performance. Temperatures are a function of the natural geothermal conditions, but are also affected locally by the nature of the drilling fluid and cement flow processes. Knowledge of temperature conditions is essential to the success of the cement job (API, 2010). The cement design process should address several performance parameters including rheological properties, hydrostatic pressure control, fluid loss control, free fluid and sedimentation control, static gel strength development, resistance to invasion of gas or fluid, compressive or sonic strength development, shrinkage/expansion, and long-term cement sheath integrity (API, 2010). Cement additives perform several actions including altering the curing time, controlling water loss and solids/water separation, preventing damage from heat or CO_2, and preventing gas migration—among other things. The emplacement time and temperature conditions need to be considered when adjusting curing times so that the cement does not set too early – prior to reaching the desired position in the well – nor too late, leading to separation, water loss, and formation fluid entry into the cement before the cement cures. Water loss and curing reactions that result in shrinkage cracking have been identified as significant factors leading to leakage behind the casing (Dusseault et al., 2000). Various polymers are typically used to prevent water loss (Economides et al., 1998), and magnesium oxide is used to cause an expansion of the cement upon curing (Joy, 2011).

Another consideration in the cement formulation is the ability of the cement to withstand stresses and borehole flexure without fracturing. Elastomeric fibers such as polypropylene have been found to increase the elasticity of cements (Shahriar, 2011; Sounthararajan et al., 2013). Perhaps more problematic is the ability of the well cement to maintain integrity under the stress of the hydraulic fracturing treatment (Dusseault et al., 2014). Pressure testing of the casing is preferably performed prior to the wellbore cement reaching significant gel strength in the cement. This is because the pressure testing may cause cracks to form in the cement after it has reached sufficient gel strength and reacts more like a solid than a fluid. Similarly, the stress of hydraulic fracturing treatments may result in damage to the wellbore cement. One way to counter these effects is to use advanced cements capable of withstanding compressive stress without failure. Williams et al. (2011) reports on successful zonal isolation being achieved in the Marcellus Shale using a flexible expanding cement system (Pedersen et al., 2006).

The cement static gel strength measures the transition of a cement slurry from a liquid to a solid. This is important because as the gel strength rises, the ability of the cement to transmit fluid pressure decreases. The loss of static fluid pressure means that formation fluids can enter the cement-filled annulus. However, after the development of sufficient gel strength, the cement is able to block gas percolation. The cement design should limit the time period between loss of hydraulic pressure control of the formation fluids and the time when the gel strength is sufficient to block flow through the cement (Bonnet and Pafitis, 1996). Well cement-design methods and recommendations are given in the following ISO 10426 standards:

- ISO 10426-1 (ANSI/API 10A) – *Cements and Materials for Well Cementing*,
- ISO 10426-2 (ANSI/API RP 10B-2) – *Recommended Practice for Testing Well Cements*,
- ISO 10426-3 (ANSI/API RP 10B-3) – *Recommended Practice on Testing of Deepwater Well Cement Formulations*,
- ISO 10426-4 (ANSI/API RP 10B-4) - *Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure*,
- ISO 10426-5 (ANSI/API RP 10B-5) – *Recommended Practice on Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure*,
- ISO 10426-6 (ANSI/API RP 10B-6) – *Recommended Practice on Determining the Static Gel Strength of Cement Formulations*.

Cement is emplaced by pumping it down the casing, displacing drilling fluid. The cement then flows out of the bottom of the casing and enters the external annulus between the casing and the formation. In some cases, placement of cement using a reverse circulation method, in which cement is injected down the annulus, can improve the displacement of drilling fluids and result in higher compressive strength of the cement (Davies et al., 2004). The drilling fluid should be conditioned to facilitate this displacement by adjusting its properties to reduce gel strength, fluid rheology (resistance to flow), fluid density, and fluid loss to the formation within the limits of other constraints for these factors (API, 2010). Displacement of drilling fluid is also facilitated by pumping the cement at high rates, but must remain within pressure limits that allow for control of fluid loss to the formation. Movement of the casing pipe during the cement injection also improves the displacement of drilling fluids by cement. Pipe movement can be reciprocating (movement up and down the hole) or rotational. Rotational pipe movement during cementing has been found to facilitate drilling fluid displacement more effectively than reciprocating movement (API, 2010). Attaching scrapers or scratchers to the casing helps to remove gelled or dehydrated mud on the borehole wall as the casing is rotated and reciprocated (Bellabarba et al., 2008). The following standards concern testing of drilling fluids for conditioning:

- ISO 10414-1/ API RP 13B-1 – Field testing of drilling fluids -- Part 1: Water-based fluids

- ISO 10414-2/ API RP 13B-1 – Field testing of drilling fluids -- Part 2: Oil-based fluids

A chemical washer is injected ahead of the cement to help clean out the drilling mud and provide a fluid gap between the cement and the drilling mud. This helps to avoid mixing between the cement and the drilling mud. Further protection from mixing between the cement and drilling fluid is provided by wiper plugs, which are placed in front of and behind the cement slug that is injected into the casing (Nelson, 2012).

Following complete displacement of the drilling fluid by cement in the annulus, pressure should be relieved on fluid in the casing. This is to prevent overpressured conditions in the fluid causing casing strain during the cement curing period that could cause microannulus crack formation between casing and cement after pressure is relieved and the casing contracts (API, 2010).

The displacement of drilling mud and cement curing are complex processes that should be analyzed and designed using computer simulations. Simulations are needed to reveal the drilling fluid displacement and most effective annular velocities, the pressures expected to evolve, the time-temperature conditions the cement will encounter, the development of cement gel strength, and centralization/standoff conditions. This information is important for developing a successful cement design and cementing process for zonal isolation (API, 2010).

2.D.3.3. Well Integrity and Zonal Isolation

Both internal and external well integrity tests can be performed to check on the integrity of the well and the quality of the zonal isolation. Internal pressure tests check the integrity of the casing to leaks. As each casing string is emplaced and cemented, a packer is placed in the bottom of the section, and a pressure test is conducted in which the casing is subjected to a specified pressure. Leaks are indicated by a loss in pressure over time. This test pressure used depends on the anticipated pressures to be used in the well. API (2010) recommends that the pressure testing is conducted prior to achieving significant cement gel strength to avoid damage to the cement such as micro-annular cracking caused by mechanical deformation of the casing when pressurized.

Another casing leakage test is a radioactive tracer survey test. In this test, radioactive material is injected into the well and followed using a detector device on a wire line. Any leak of the injected fluid will contain radioactive tracer. The movement of the leaked tracer material is unlikely to keep pace with the movement of the injected material containing the tracer, which continues down the well (U.S. EPA, 2008).

External well integrity tests evaluate the ability of the cement to prevent leakage around the casing shoe and along the outside of the casing. An external integrity test often used is called the formation integrity test. For this test, the cement at the base of the well is drilled out, and pressure is applied to the drilling fluid until pressure rises to the maximum pressure expected at the base of the current casing string during well drilling (API, 2010). If it cannot hold this pressure, remedial cementing is needed. An alternative type of test, called the cement bond log, uses acoustical transmitters and receivers in the wellbore to detect difference in sound transmission and reflection through the casing and cement back to the acoustical receivers. While cement bond logs can detect large areas where cement is absent or not bonded to the casing, they are not sensitive enough to find small channels in the cement bonding to the casing which could act as leakage flow pathways behind casing (Bellabarba et al., 2008). Other tests for behind casing leaks include temperature logs, noise logs, oxygen activation logs, and radioactive tracer surveys (U.S. EPA, 2008).

Appendix 2.E

Communication from Chevron Regarding Disposal of Produced Water into Unlined Pits

CCST: Can Chevron provide us with a written statement, on the record, stating how they dispose of produced water from wells in which production is facilitated by well stimulation (i.e. what proportion of produced water goes to evaporation/percolation ponds versus Class II wells)?

Chevron:
In terms of what proportion of produced water goes to evaporation/percolation ponds versus Class II wells, in areas where Chevron conducts SB 4 well stimulation treatments, no produced water goes to evaporation/percolation ponds. A portion of the produced water is disposed of in DOGGR permitted Class II injection wells and a portion of the produced water is recycled for enhanced oil recovery use.

Chevron's Lost Hills percolation ponds were closed (February 2009) and remediated several years ago whereupon the post-closure requirements are being managed in accordance with WDR R5-2013-0056 (attachment from Chevron not included). The Waste Discharge Requirements (WDR) describes the history of those percolation ponds including when they were closed and remediated.

NOTE: Following the October 28, 2014, meeting with CCST members, Chevron began review of DOGGR's records to find out why DOGGR records show Chevron's water disposal still going into unlined pits. We discovered that an **incorrect code** is being used to report our data to DOGGR. We will contact DOGGR to correct the records.

Appendix 2.F

Communication with Aera Energy Regarding Recovered Fluid Data From the Completion Reports

From: "Besich NP (Nick) at Aera" <NPBesich@aeraenergy.com>
Subject: RE: well stimulation data questions
Date: July 16, 2014 at 2:52:45 PM PDT
To: Preston Jordan <pdjordan@lbl.gov>
Cc: Frac <Frac@aeraenergy.com>

Preston,

All the samples submitted as recovered fluid samples have been of recovered fluid. ¬†None have been of produced fluid. ¬†

We try to get the sample somewhere in the middle of the recovery, however, operationally this doesn't always end up being the case. ¬†Keep in mind that these recovered fluids are recovered by circulating the fluid out of the wellbore with water so the samples being collected could be a mixture of unknown proportions of stimulation fluid, reservoir fluid (i.e. oil/water that was in the reservoir prior to stimulation), and cleanout fluid.

From our water management plan that we submit with our NOI: "water recovered during well cleanout operations after the stimulation treatment is either reused for the next job, or passed through a water treatment facility and transported to Aera's permitted Class II disposal wells"

Note: The next job refers to the next cleanout job, not the next frac job. We don't recycle the recovered fluid and reuse it as well stimulation base fluid. ¬†

If you have additional questions, I'd encourage you to email the frac@aeraenergy.com email rather directly to my email. ¬†We want to have a non-person dependent email history of all frac related regulatory discussions, so if I ¬†or others here move on to other things, the history of our work is saved with that inbox.

Thanks

Nick Besich
Production Engineer
Development Team
Aera Energy LLC
Office: 661.665.5789
Cell: 661.667.1164
nbesich@aeraenergy.com

-----Original Message-----
From: Preston Jordan [mailto:pdjordan@lbl.gov]
Sent: Tuesday, July 15, 2014 11:42 AM
To: Besich NP (Nick) at Aera
Subject: Re: well stimulation data questions

Hello again Nick-

I shared your information with the team here yesterday and they appreciated it. ¬†Thank you again.

Probably no surprise, a couple of additional questions came up, if you are willing to humor us a bit further.

The submitted completion data posted by DOGGR includes water analyses results. ¬†From looking at a few of them, they appear to typically be from analyses of samples taken the day after the completion of the hydraulic fracturing operation. ¬†It is not stated whether the samples are of recovered or produced water. ¬†The timing suggests the samples were taken from recovered fluid. ¬†If so, we don't know if the samples were generally taken from at the beginning, middle or end of the recovery. ¬†This is relevant in part because it would provide some information on which to judge whether the fluid was ever in contact with the reservoir. ¬†Any general information you can provide regarding sample timing and practice would help us more appropriately consider those data.

The other question regards disposal of the recovered fluid. ¬†Is it generally trucked to a treatment plant, pumped into the production pipeline that is brought to the well, or disposed of in some other manner.

Thank you again.

Preston

On 7/14/2014 8:26 AM, Besich NP (Nick) at Aera wrote:
Preston,

The units are in barrels. ¬†They are not percentages.

We consider recovered fluid to be the fluid that is removed from the well prior to it being turned on production or injection. ¬†This recovered fluid does go into a tank. ¬†Any fluid recovered after the well is turned on production is considered produced fluid and is handled as such.

If you have any other inquiries feel free to cc me directly on the email.

Nick Besich
Production Engineer
Development Team
Aera Energy LLC
Office: 661.665.5789
Cell: 661.667.1164
nbesich@aeraenergy.com

-----Original Message-----
From: Preston Jordan [mailto:pdjordan@lbl.gov]
Sent: Wednesday, July 09, 2014 12:12 PM
To: Frac
Subject: well stimulation data questions

Hello-

I am a researcher at Lawrence Berkeley National Laboratory and a member of a research team conducted a scientific review of well

stimulation in California for the California Department of
Conservation, which includes DOGGR. ¬†Thank you for submitting data to
DOGGR regarding well stimulations performed by Aera Energy this year. ¬†
We are working with the data DOGGR has posted
(ftp://ftp.conservation.ca.gov/pub/oil/Well_Stimulation_Treatment_Disc
losures/20140507_CAWellStimulationPublicDisclosureReport.xls,
although note the file appears to actually be an xlsx).

I am contacting you regarding the recovered fluid data DOGGR has posted. ¬†The
header indicates the units are bbls. ¬†The values for Aera Energy's stimulations
are all less than 100 I believe and some are less than 10. ¬†This compares to
median water volume injected of about 1600 bbls. ¬†This has led some here to
wonder if the recovered water data is actually in percent rather than bbls.
¬†Consequently confirmation that the recovered fluid volume data is in bbls
would be appreciated.

A related question is what is recovered fluid? ¬†This could be taken as similar
to the question what is flowback versus produced water, which does not appear to
have a definitive answer. ¬†One hypothesis here for the working distinction
between recovered versus produced water is how each is handled, with recovered
going into tanks at the site initially and produced going into the field
pipeline system.

Thank you for considering these questions. ¬†I welcome a phone call if you would
like to discuss these questions, and perhaps the project upon which we are
working. ¬†In the interest of forestalling possibly redundant effort to respond,
it is worth mentioning I also left a voice mail for Nick Besich. ¬†He is listed
by DOGGR as having submitted the Aera's data.

Take care.

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Appendix 2.G

Data on Wastewater Disposal Ponds

This is a large dataset that could not be easily formatted for this report. These data are available electronically at http://ccst.us/publications/.

At the time of publication, there was no single database of oil and gas wastewater disposal ponds or "sumps" in California. We compiled information that we acquired from two state agencies into a single data table. The original sources of these data are the following three worksheets:

- **CVRWQCB 2015**: *Produced Water Pond List*, spreadsheet dated April 15, 2015, posted at http://www.swrcb.ca.gov/centralvalley/water_issues/oil_fields/information/disposal_ponds/2015_0415_prod_pond_list.pdf.

- **Borkovich 2015a**: *San Benito sumps (1).xlsx*, spreadsheet emailed to Laura Feinstein, CCST, by John Borkovich of the State Water Resources Control Board on March 28, 2015.

- **Borkovich 2015b**: *DOGGR District 3 Sump Search (1).xlsx*, spreadsheet emailed to Laura Feinstein, CCST, by John Borkovich of the State Water Resources Control Board on March 28, 2015.

There are a total of 754 records in the combined data table. Most records represent single ponds, but some represent pond complexes with 4 to 27 ponds in them. There are a total of 950 ponds.

Table 2.G-1. Description of fields in the sumps data table.

Column	Description
ID	Unique ID assigned to each row
Field	Name of the oil or gas field, also referred to as DOGGR Administrative Boundary.
Lease	Name of the lease.
Operator	Name of the operator.
Location	A text description of the pond's location.
Benchmark	PLSS location information
Township	PLSS location information
Range	PLSS location information
Section	PLSS location information
Geo_Note*	A custom field I added indicating whether the coordinates were provided in the original source or estimated in GIS, in which case they are less accurate.
Latitude	The approximate latitude of the pond or pond complex (coordinate system assumed to be WGS84).
Longitude	The approximate longitude of the pond or pond complex (coordinate system assumed to be WGS84).
Status	Active, Inactive, Unknown
Num_Sumps	The number of ponds represented by a point. This field contains a number greater than one 1 for pond complexes
Source	Data source, 1 of 3 spreadsheets emailed to SB4 investigators.
DOGGR_District	DOGGR District. There are 6 Districts in total. See: http://www.conservation.ca.gov/dog/pages/doggr_contacts.aspx.
WQ_District	The Water Quality Administrative Region in which the point is located. There are 9 regions in California. See: http://www.waterboards.ca.gov/waterboards_map.shtml.
County	The county where the point is located.

** Where a record of a pond or pond complex did not have latitude/longitude coordinates, we assigned approximate coordinates using other location information. Most records had Public Land Surveying System information, i.e., Range, Township, Section. Where this information was available, we assigned the centroid of the Section, which should be accurate to within 1 mile, which is good enough for making small-scale (zoomed out) maps. In a few cases, the only location information available was the name of the oil or gas field. In these cases, we located the ponds using aerial imagery and assigned the coordinates to their likely location.*

Appendix 2 References

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