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Increased Oil Production And Reserves From Improved Completion Techniques In The Bluebell Field, Uinta Basin, Utah

Contract DE-FC22-92BC14953

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INCREASED OIL PRODUCTION AND RESERVES FROM IMPROVED COMPLETION TECHNIQUES IN THE BLUEBELL FIELD, UINTA BASIN, UTAH

Contract No. DE-FC22-92BC14953

Utah Geological Survey (UGS)
Salt Lake City, Utah

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Objectives

The objective of this project is to increase oil production and reserves in the Uinta Basin by demonstrating improved completion techniques. Low productivity of Uinta Basin wells is caused by gross production intervals of several thousand feet that contain perforated thief zones, water-bearing zones, and unperforated oil-bearing intervals. Geologic and engineering characterization and computer simulation of the Green River and Wasatch formations in the Bluebell field will determine reservoir heterogeneities related to fractures and depositional trends. This will be followed by drilling and recompletion of several wells to demonstrate improved completion techniques based on the reservoir characterization. Transfer of the project results will be an ongoing component of the project.

Summary of Technical Progress

Subsurface Studies

<u>Mapping:</u> Structure and isopach maps were constructed covering the Roosevelt Unit area in the eastern portion of the Bluebell field where the demonstration sites are located. The structure contour map of the middle marker of the Green River formation (top of the upper Wasatch transition) illustrates a west plunging anticline (Fig. 1). The structure contour map of the lower Wasatch transition shows north dip toward the basin axis. The anticline at shallow depths is absent at the deeper lower Wasatch transition horizon (Fig. 2). The isopach map of the Wasatch formation shows the general north to south thinning of the thick fluvial redbed deposits (Fig. 3). The isopach map of the lower Wasatch transition shows a lobate depositional pattern interpreted to be lower deltaic to shallow lacustrine deposits (Fig. 4). Thick, channel-sandstone deposits in the Wasatch redbed sequence are overpressured productive reservoirs in the western portion of the field. In the eastern portion of the field the overpressuring occurs near the top of the lower Wasatch transition (below the redbed sequence) and is the primary deep productive interval.

<u>Core:</u> Integrated analysis of petrography, porosity, and permeability data from core, suggests that clastic rocks, particularly arenites with less than 2% clay content, have the highest porosities and permeabilities in the subsurface (in unfractured samples). Lithology with more than 2% clay content have less than 8% porosity with permeabilities less than 0.05 millidarcies (mD).

Predominant clay minerals identified by XRD in the subsurface are illite, chlorite, and kaolinite, with very little smectite in mixed layers with illite and/or chlorite. There is much less swelling clay in the subsurface in the center of the Uinta Basin than there is in outcrop on the southern flank of the Basin.

Fracture analysis indicates that fractures in the subsurface are present in 86%

of the wackestone, 79% of the packstone, and 74% of the sandstone. Fracture density in sandstone is low relative to other rock types, but the fractures in sandstone are relatively wide, open, and vertical. The fracture density within limestone mudstone appears to increase with increasing thickness of the unit. This may also be true of packstone. Thin sandstone units show no preference relative to fracture density, but as sandstone units thicken, fracture density tends toward the moderate range. Researchers found no obvious relationship between fracture density and depth with any lithology.

Log and Petrophysics: Naturally occurring fractures play an important role in hydrocarbon production but for long-term production, intergranular permeability (>0.1 mD) and intergranular porosity are needed. Core studies show that in-situ fractures occur in carbonate (including marl) and sandstone, but are rare in shale. Based on core-plug analyses, intergranular permeability of >0.1 mD occurs only when clay content is < 2% to 4% and intergranular porosity is >4%.

Log analysis has shown that clay content can be accurately estimated from the CGR log (potassium (K) + thorium (Th) contributions to total gamma radiation). Uranium however, is not present uniformly in clays and is therefore not correlated with CGR, K, or Th. Consequently, total gamma ray is a less reliable indicator of clay content than is CGR from spectral gamma ray. A potential complication in the use of either spectral or total gamma-ray logs for clay estimation is that an immature clay-free sandstone or limestone can have the same gamma-ray response as a mature, clay-containing sandstone or limestone, although only the clay-free rocks have good intergranular permeability. However, preliminary analysis suggests that this problem is not common.

Analysis of core plugs show that grain densities are generally lower than been expected, averaging 2.66, in contrast to the normally assumed matrix value of 2.68 in the eastern part and 2.71 in the western part of the field. As a result, density porosity is often overestimated. Feldspar content may account for the lower-than-expected grain density.

The best log-based estimate of porosity for shale-free rocks is the average of density-porosity and neutron-porosity, both calculated using a limestone matrix. The biases in both the neutron-porosity and density-porosity measurements are of opposite sign and approximately cancel (within about one porosity unit). Washouts must be avoided because they give unreliably high porosity readings, but fortunately washouts are less common in shale-free rocks than in shaley rocks. For wells in which a sonic log was run without a density/neutron log, porosity can not be accurately determined even when the analysis is confined to shale-free rocks, because of lithology-dependent variations in matrix travel time.

Fractures: Two sets of subsurface fractures are present across the field, but appear to be vertically segregated from each other. The orthogonal fractures prevalent at the surface are not present in the subsurface.

East-west fractures are associated with the most productive wells. Northwest-southeast fractures occur above the E-W set. Some wells bottom in rocks with the NW-SE set so it is not certain the E-W set exists at depth everywhere in the field.

The transition from NW-SE to E-W trending fractures occurs at different depths in each well, in both absolute and stratigraphic terms. The transition is shallowest (occurring between -1500 and -3100 ft subsea) in the Pennzoil Lamb 2-16A2 well, which is the most westerly and northerly of the five wells with fracture data. In the Pennzoil Cornaby 2-14A2 well the transition is at approximately -4600 ft. Both wells have all of their perforations in horizons with E-W fractures. Both wells are in sections where cumulative production exceeded 2 million bbl of oil per well. The transition is in the Green River formation in both wells.

In the Pennzoil (formerly Gulf) Johnson 1-27A2, only NW-SE trending fractures are present. The E-W fractures may occur below total depth of the well, 13,617 ft (-7980 ft subsea). The well bottomed in the Wasatch formation. Cumulative production of this long time producer has been less than 500,000 bbl of oil.

Flying J's Ute 2-22A1E well has a poorly defined transition at around -7300 ft subsea in the Wasatch formation. There is only 15° of azimuthal variation between the two "sets" of fracture trends. A preponderance of perforations are in the lower, more E-W trending fractured rocks. Cumulative production has been about 800,000 bbl of oil for this well.

In a general sense, the wells in the Bluebell field with the greatest number of perforations in horizons with E-W fractures have the greatest cumulative production. Wells with all or most perforations in rocks with the NW-SE trending fractures have significantly lower cumulative production. This suggests that the E-W fractures are the primary source of producible oil.

The Pennzoil Ballard 2-15B1 well is perforated primarily in rocks with NW-SE fractures, but is a new well with a limited production history. If the E-W fractures simply rotate into the NW-SE set as they move eastward, the above correlation suggests that the Ballard well should ultimately be an excellent producer. However, the initial well in the same section has only a small fraction of the cumulative production compared to the better wells in the field.

Engineering Studies

Oil production from the Michelle Ute and Malnar Pike wells were history matched using homogeneous reservoir simulation models. The original-oil-in-place (OOIP) minus the oil produced show that a significant portion of the OOIP still exists in both wells (tables 1 and 2). In both wells new beds were perforated over a period of years. The Michelle Ute has three sets of perforations while the Malnar Pike has two sets. In history matching the performance of these two wells, this production history was reproduced in the reservoir simulators. In both wells the first set of perforations accounted for most of the oil produced. In the homogenous models low absolute permeabilities were used to match the production data. It was necessary to use progressively lower permeabilities in both wells, as new perforations were added. The layers representing the first set of perforations in Michelle Ute had permeabilities of about 0.6 mD, while the second and the third sets had permeabilities of 0.1 and 0.07 mD respectively. The layers with the first set of perforations in the Malnar Pike well had permeabilities of 0.34 mD and the second set had permeabilities of 0.016 mD. The low permeabilities employed in the history match indicate: (1) even though there is a great deal of oil still in the reservoir, unless the permeabilities are enhanced by some means, it is not producible at economic rates and (2) the new zones opened have lower permeabilities than initially opened zones. It may be that formation damage continues behind pipe, in unperforated zones, so that when they are eventually perforated these zones do not produce as well as the initially opened zones or, the stimulation treatments are less effective as more beds are added.

The homogeneous models of the Michelle Ute and Malnar Pike wells show that the wells only drain a 400 ft radius. Even in the 400 ft radius area, the remaining oil saturations are fairly high. The pressure influence is also felt over a similar distance. Single-well simulations were also performed using dual-porosity, dual-permeability fractured models. These fractured reservoir models reveal that the radius of influence of the two wells is larger due to the presence of fractures. The radius of influence is shown to be about 1000 ft. Most wells in this part of the Bluebell field are drilled at only one well per section. Therefore, most of the oil in a section is not being drained.

TABLE 2
Reservoir Characteristics of all the Producing Zones in the Malnar Pike Well

ZONE	DEPTH (ft)	THICKNESS (ft)	POROSITY	So	OOIP (from So) (bbl)	OOIP (So=0.7) (bbl)	OIL PRODUCED (bbl)
1	9582	10	0.08	0.64	99639	108980	574
2	9914	6	0.18	0.61	128207	147123	646
3	9925	3	0.05	0.37	10801	20434	130
4	9933	4	0.04	0	0	21796	151
5	9940	3	0.07	0.51	20842	28607	127
6	9950	16	0.07	0.45	98042	152572	822
7	10054	18	0.03	0.61	64103	73561	610
8	10074	4	0.2	0.72	112094	108980	539
9	10081	3	0.1	0.55	32110	40867	847
10	10101	12	0.1	0.8	186823	163470	786
11	10289	24	0.07	0.8	261552	228858	1066
12	12702	4	0.09	0.56	39233	49041	358
13	12716	4	0.14	0.74	80645	76286	449
14	12976	4	0.09	0.53	37131	49041	349
15	13026	8	0.14	0.78	170008	152572	716
16	13084	9	0.17	0.78	232244	208424	869
17	13136	6	0.18	0.74	155530	147123	664
18	13165	15	0.15	0.83	363428	306506	1154
19	13186	4	0.17	0.8	105866	92633	500
20	13200	6	0.32	0.86	321335	261552	827
21	13224	8	0.09	0.74	103687	98082	601
22	13276	4	0.14	0.65	70837	76286	459
23	13336	10	0.14	0.76	207062	190715	857
24	13370	8	0.16	0.7	174368	174368	808
25	13402	10	0.12	0.68	158799	163470	844
26	13425	8	0.07	0.51	55580	76286	560
27	13434	4	0.08	0.45	28023	43592	324
28	13486	8	0.08	0.63	78465	87184	572
29	13500	6	0.16	0.7	130776	130715	615
30	13516	10	0.14	0.72	196164	190715	821
31	13570	14	0.12	0.65	212511	228858	1016
32	13588	6	0.09	0.63	66205	73561	498
33	13600	10	0.06	0.1	11676	81735	610
34	13826	14	0.12	0.56	183086	228858	8457
35	13854	6	0.06	0.55	38532	49041	3003
36	13898	8	0.1	0.6	93411	108980	5049
37	13986	2	0.1	0.65	25299	27245	1444
38	13970	6	0.12	0.58	81268	98082	4162
39	13986	10	0.06	0.6	70058	81735	4540
40	14060	6	0.14	0.43	70292	114429	4605
41	14082	6	0.18	0.65	136614	147123	5068
42	14118	8	0.06	0.63	58849	65388	3830
43	14140	6	0.06	0.43	30125	49041	2984
44	14160	2	0.06	0.3	7006	16347	1119
45	14168	4	0.07	0.51	27790	38143	2239
46	14184	6	0.1	0.68	79400	81735	3806
47	14266	13	0.07	0.65	115110	123965	6148
48	14350	10	0.1	0.5	97303	136225	6042
	TOTAL				**5198804**	**5496669**	**86484**

So: oil saturation
OOIP: original-oil-in-place

TABLE 1

Reservoir Characteristics of all the Producing Zones in the Michelle Ute Well

ZONE	DEPTH (ft)	THICKNESS (ft)	POROSITY	So	OOIP (from So) (bbl)	OOIP (So=0.7) (bbl)	OIL PRODUCED (bbl)
1	10414	2	0.04	0.50	8540	11956	259
2	10448	2	0.02	0	0	5978	203
3	10470	12	0.02	0.29	14860	35868	1123
4	10521	10	0.08	0.78	133224	119560	1511
5	10603	1	0.03	0	0	4484	124
6	10709	9	0.08	0.8	122976	107604	1399
7	10795	6	0.09	0.76	87620	80703	1037
8	10861	14	0.09	0.86	321349	188307	2230
9	10938	11	0.09	0.78	164865	147956	1759
10	11188	5	0.04	0.15	6405	29890	708
11	11237	1	0.04	0.21	1793	5978	144
12	11707	1	0.03	0	0	4484	134
13	11777	6	0.15	0.53	101840	134505	1293
14	11827	1	0.10	0.58	12383	14945	213
15	11937	1	0.14	0.65	19429	20923	234
16	11955	1	0.15	0.57	18254	22418	235
17	12348	1	0.06	0.27	3459	8967	189
18	12438	1	0.16	0.72	24595	23912	232
19	12989	6	0.12	0.65	99918	107604	6563
20	12997	2	0.05	0.25	5338	14945	1316
21	13002	4	0.11	0.74	69516	65758	4212
22	13010	8	0.09	0.46	70711	107604	7317
23	13023	6	0.05	0.61	70327	80703	5574
24	13096	4	0.05	0.22	9394	29890	2595
25	13102	4	0.06	0	0	29890	2592
26	13221	6	0.06	0.26	19984	53802	4351
27	13320	4	0.06	0.02	1025	35868	2913
28	13328	4	0.09	0.46	35356	53802	3723
29	13347	2	0.05	0.25	5338	14945	517
30	13358	1	0.05	0.16	1708	7473	259
31	13363	2	0.05	0.12	2562	14945	517
32	13409	6	0.16	0.67	137323	143472	7754
33	13547	6	0.06	0.38	29207	53802	4254
34	13652	2	0.05	0.16	3416	14945	518
35	13804	4	0.04	0.21	7174	23912	2172
36	13854	6	0.07	0.55	49319	62769	4613
37	13873	2	0.05	0.31	6619	14945	527
38	13899	6	0.09	0.56	64562	80703	5409
39	13999	6	0.04	0.15	7686	35868	3109
40	14008	4	0.04	0	0	23912	2096
41	14067	2	0.07	0.11	3288	20923	597
42	14077	4	0.06	0.51	26132	35868	1091
43	14284	6	0.06	0.38	29207	53802	4090
44	14435	7	0.06	0.38	34075	62769	4679
45	14443	4	0.06	0.18	9223	35868	2690
	TOTAL				**1840000**	**2249225**	**99075**

So: oil saturation
OOIP: original-oil-in-place

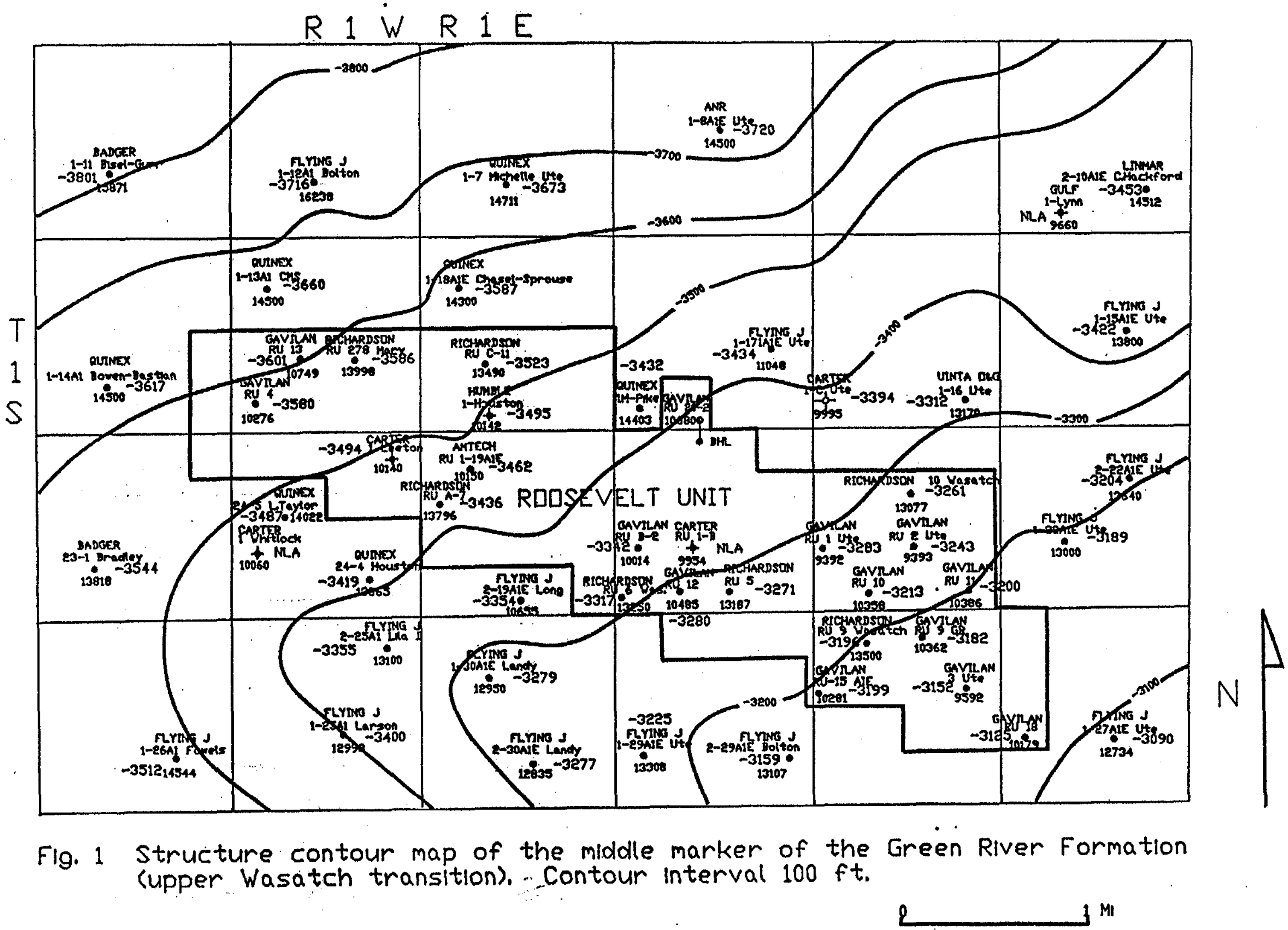

Fig. 1 Structure contour map of the middle marker of the Green River Formation (upper Wasatch transition). Contour interval 100 ft.

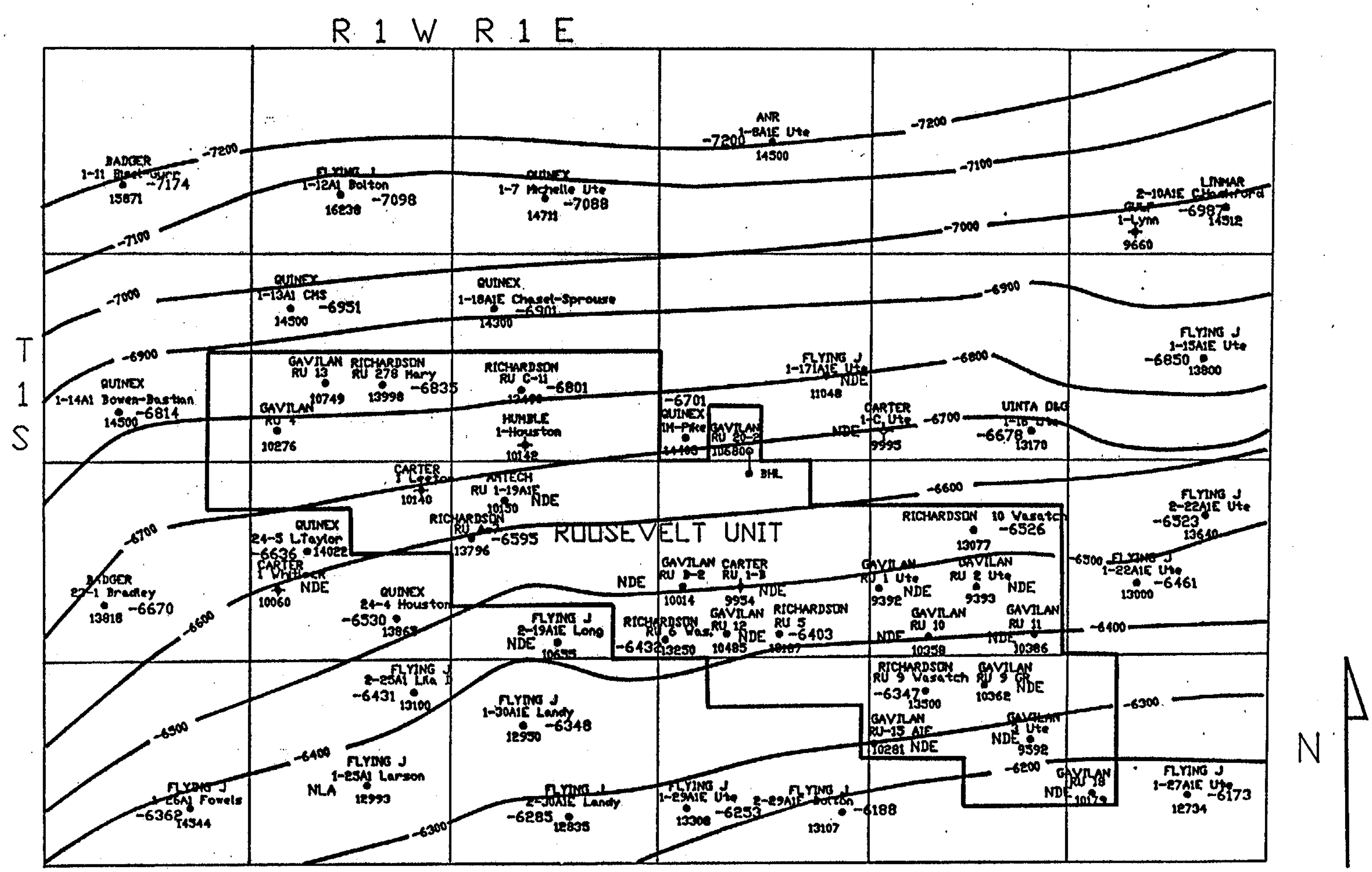

Fig. 2 Structure contour map of the lower Wasatch transition. Contour interval 100 ft.

0 1 MI

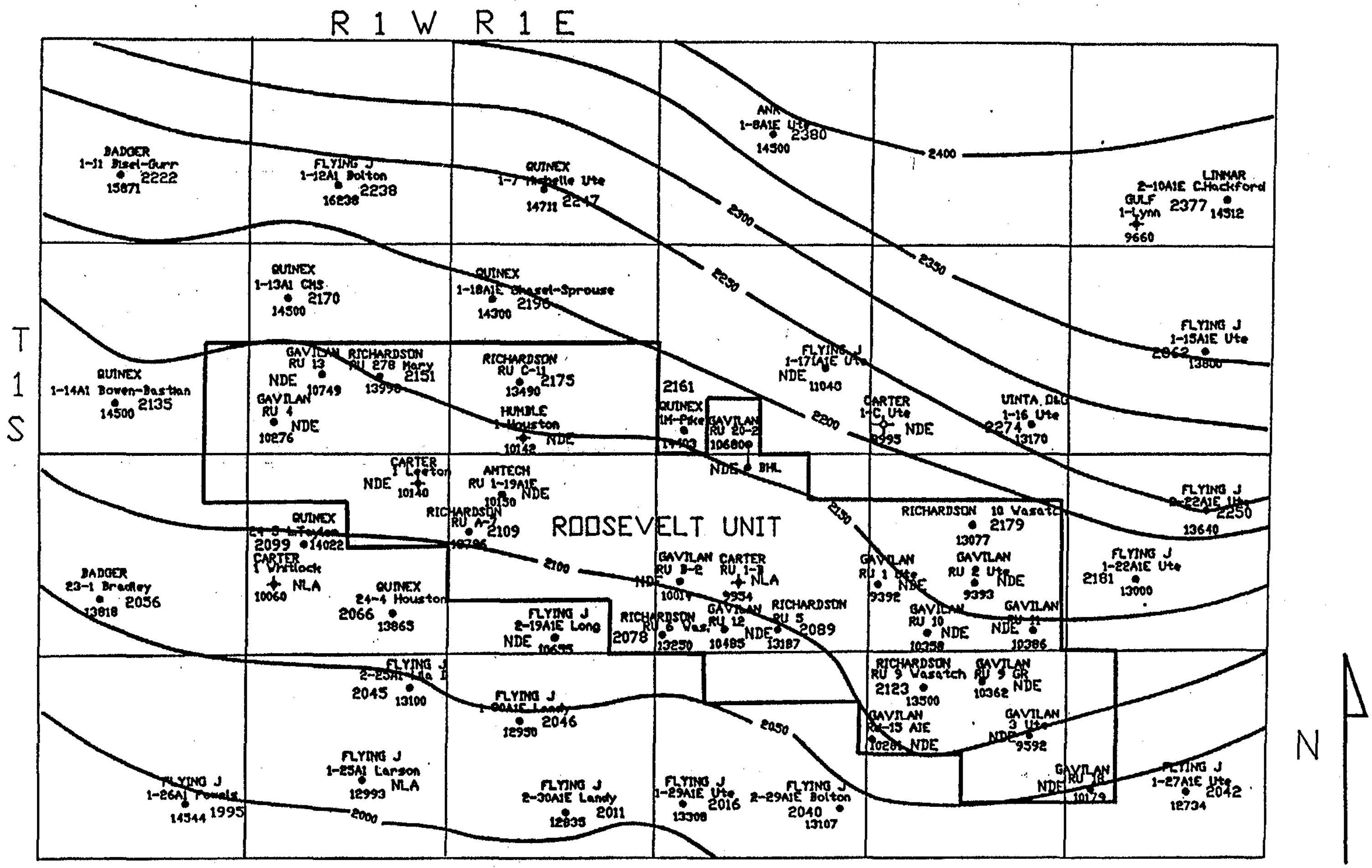

Fig. 3 Isopach map of the Wasatch Formation. Contour interval 50 ft.

0 1 MI

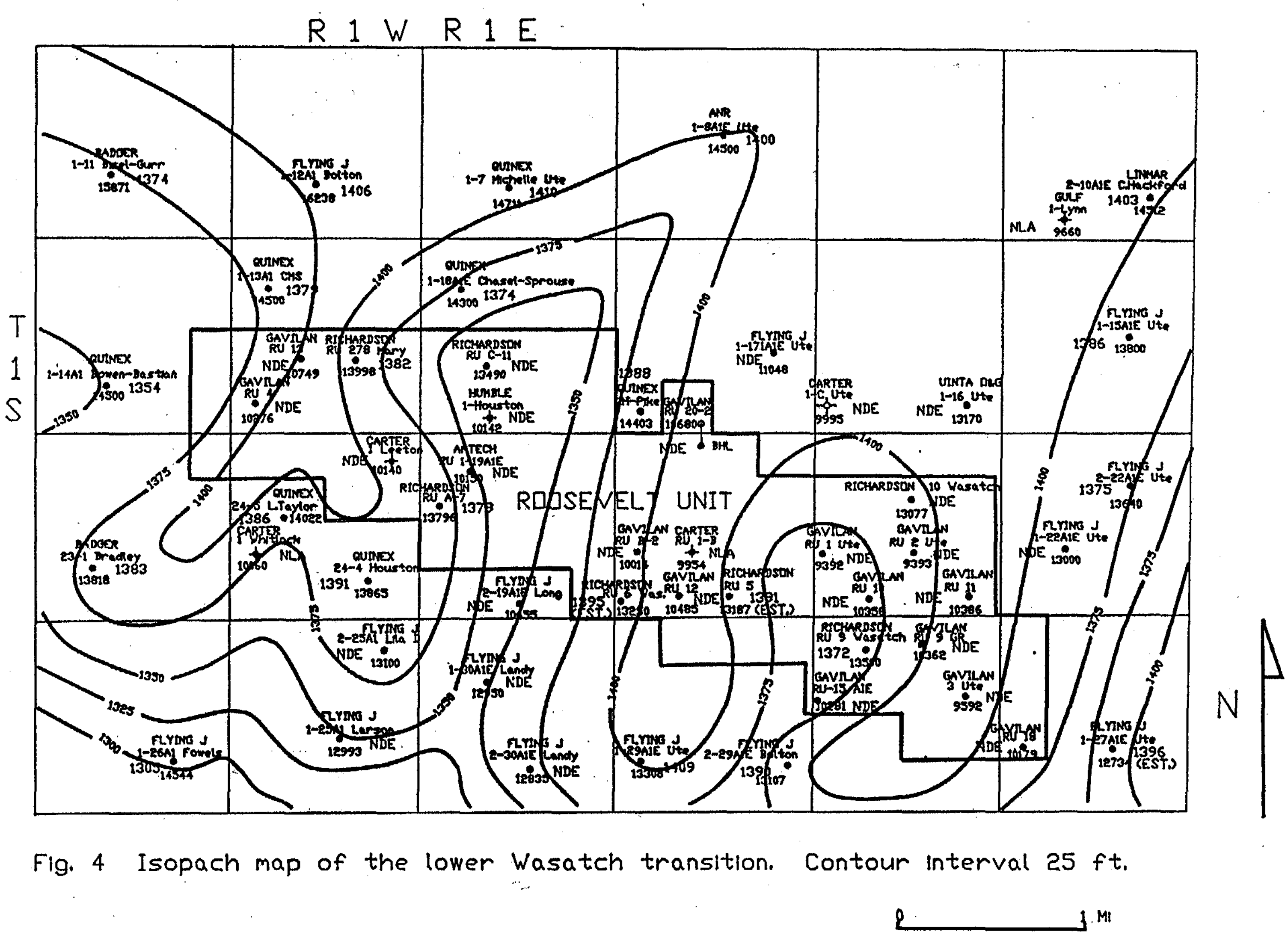

Fig. 4 Isopach map of the lower Wasatch transition. Contour interval 25 ft.