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SHALE GAS IN THE SOUTHERN CENTRAL AREA OF NEW YORK STATE

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GOVERNMENT DOCUMENT

Volume II

Experience of Locating and Drilling Four Shale-Gas Wells in New York State

Prepared for

NEW YORK STATE
ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

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PREFACE

This report is presented in two volumes. The first volume is a general discussion of shale gas in New York State and of the methods by which it may be obtained; this volume is intended to be a "how-to manual" for organizations considering drilling for shale gas. The second volume relates specific experience in locating and drilling four shale-gas wells in New York State.

Four shale-gas wells have been located and drilled in the south-central area of New York State as part of this project. The four wells that were drilled are:

The Rathbone well, in Steuben County, was located on the north side of a graben, in an old shale-gas field; it penetrated the Rhinestreet, Geneseo and Marcellus shales. Artificial stimulation was performed in the Rhinestreet, without marked success, and in the Marcellus; the latter formation has a calculated open flow of 110 Mcf/day and appears capable of initial production of 100 Mcf/day against a back-pressure of 500 psi.

The Dansville well, in Livingston County, tested the Geneseo and Marcellus shales at shallower depth. Artificial stimulation was performed in the Marcellus. The calculated open flow is 95 Mcf/day, and the well appears capable of initial production of 70 Mcf/day against a back-pressure of 300 psi.

The Erwin and N. Corning wells, both near Corning in Steuben County, were designed to test the possibility of collecting gas from a fractured "conduit" layer connecting to other fracture systems in the Rhinestreet shale. The N. Corning well failed; the expected conduit was found to be only slightly fractured. The Erwin well encountered a good initial show of gas at the conduit, but the gas flow was not maintained; even after artificial stimulation the production is only 10 Mcf/day.

The present conclusion is that the most likely source of shale gas in south-central New York is the Marcellus shale formation. Important factors not yet established are the decline rate of Marcellus production and the potential of the Geneseo after stimulation.

2.1 INTRODUCTION

During 1980, four shale wells were drilled in south-central New York as a part of the present contract. This report sets out recommendations for locating and drilling shale wells; these recommendations are based in part on the experience of drilling four wells.

2.2 THE RATHBONE PROSPECT

The old maps of the oil and gas fields of New York include a shale-gas field at Rathbone. The Rathbone field is said to have produced from the Rhinestreet (and locally from the Nunda, which is a shallow siltstone above the Rhinestreet). The Rathbone prospect was conceived to test whether the old field could be revitalized by modern stimulation techniques.

Initially the plan was merely to drill in the largest undrilled void within the old field, and to test the Rhinestreet only. In fact, it became possible to apply some additional criteria to the well location, and to drill through all three shales — the Rhinestreet, the Geneseo and the Marcellus. The latter development was possible because the Rathbone site was suitable as a well location in the DOE's shale-characterization program — which called for a core in the Geneseo and Marcellus. The success of the Rathbone well (in the Marcellus) is due to this happy circumstance; in the Rhinestreet, as proposed, it would have been a dry hole.

The original rationale for the location of the well is given in Appendix II 2.1. Information gained since the well was drilled generally confirms this rationale, except that the flex orientation may be closer to N60^{o}E than N65^{o}E; it is likely that the well is at the north edge of a graben in the Onondaga, and that the down-to-south flex in the Tully is matched by a down-to-north equivalent over the other edge of the graben to the south.

The well, named the Valley Vista View no. 1, was drilled on a farm-out from Columbia Gas Transmission Corp. The location is given in Figure 2.3-1. The well was spudded on 21 July, 1980. The monthly summaries of drilling reports are given in Appendix II 2.2. The daily drilling reports are given in Appendix II 2.3.

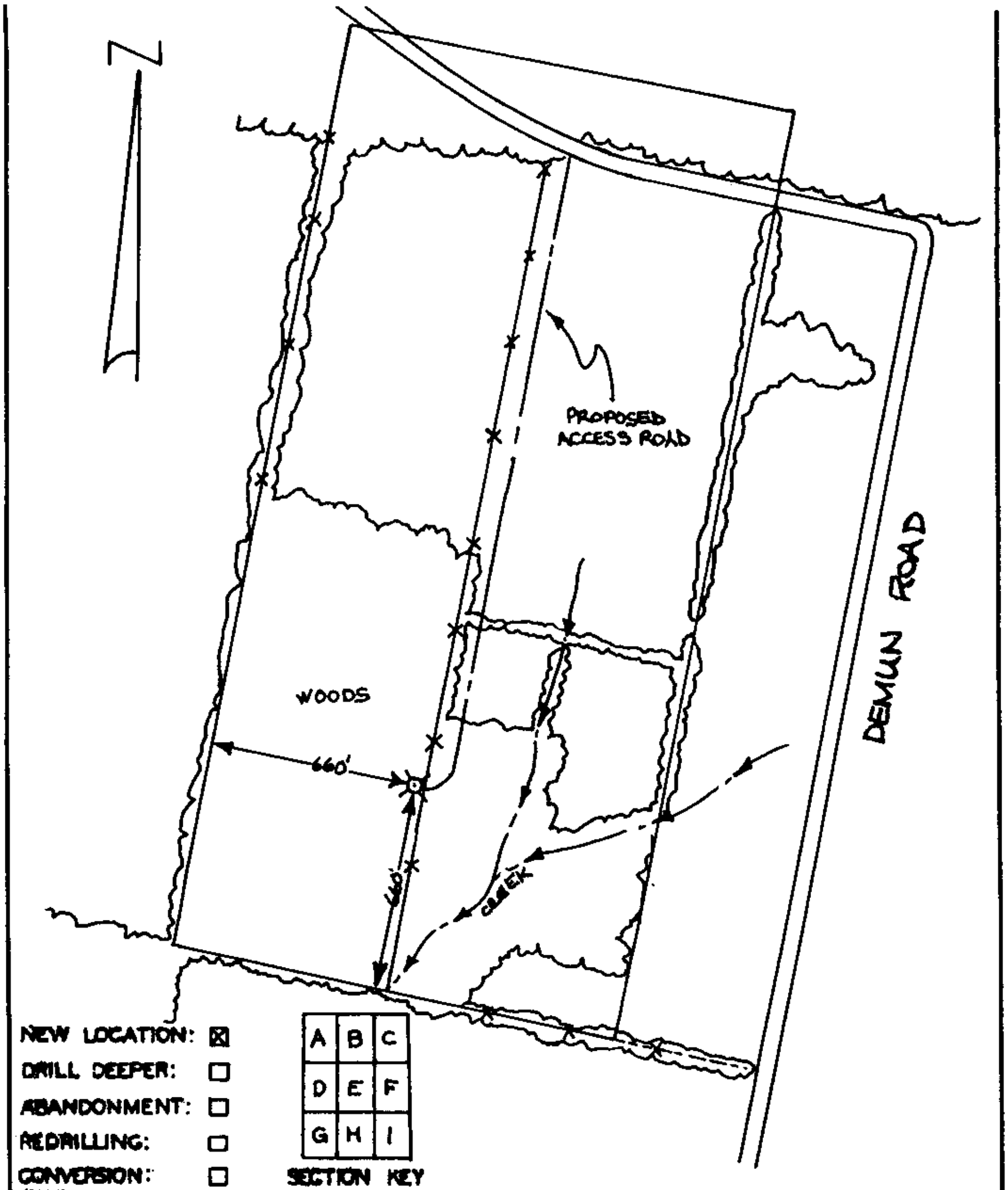
One unexpected development during the drilling was a major flow of gas (1300 Mcf/d) at 681 ft. This shallow gas blew down in a few days, and might therefore be dismissed as a mere nuisance. However, it is relevant in two contexts. First, it places the old well records in perspective; the early promotors of the Rathbone field would probably have claimed 1300 Mcf/d as the initial production of the well. Second, it illustrates that copious shallow gas may be an indicator of a deep source and an extensive fracture system, as suggested in Volume I (1.3.6).

A second unexpected development during the drilling was a very thick Marcellus. This thickening was due in part to steep dip at this level, and in part to a double reverse fault — which meant that parts of the Marcellus section were drilled twice.

Good cores were obtained in the Geneseo and the upper Marcellus. Both cores were very black, very rich, and bleeding gas; the organic richness has since been confirmed quantitatively by the Mound facility of Monsanto, under a separate DOE contract. The Marcellus core (as might be expected from the double fault), was highly fractured; a fracture analysis by Cliffs Minerals (again under a separate DOE contract) shows the prevailing orientation of the natural fractures to be NW-SE. This suggests that the fractures are occasioned by relief movement at right angles to the orientation of the major graben.

The well was logged with a full research suite of logs (both dry-hole and wet-hole); these logs — and the logs of the other three wells reported herein — remain on open file with the DOE at Morgantown Energy Technology Center, W VA. A mud-logger was also used, below about 700 ft.

After consideration of all the logs, it was decided (in consultation with the experts at DOE) that the planned stimulation of the Rhinestreet should be sup-



COMPANY: ARLINGTON EXPLORATION COMPANY
ADDRESS: 137 NEWBERRY ST. BOSTON MA. 02116
LANDOWNER: VALLEY VISTA VIEW, INC.
TRACT: ______ ACRES: 100 LEASE NO. ______
WELL (FARM) NO. 1 SERIAL NO. ______
ANGLE OF DEVIATION, IF ANY: ______
ELEVATION: 1451'
LATITUDE: 42°09'54" N
LONGITUDE: 77°21'14" W
DISTANCE SOUTH OF NORTH: 31,350' AND
WEST OF EAST: 28,150' IN SECTION: G
(SEE KEY ABOVE) OF RATHBONE, N.Y. QUADRANGLE
☒ 7.5 MIN. ☐ 15 MIN. MAP DATE: 1953
TOWN: RATHBONE COUNTY: STEUBEN
SIGNED: Roderick D. McConnell L.S. 49158
DATE: APRIL 14, 1980 SCALE: 1" = 400'

NEW YORK STATE
DEPARTMENT OF
ENVIRONMENTAL CONSERVATION
BUREAU OF MINERALS

WELL LOCATION MAP

D.E.C. FILE NO. ______

Gowdy and Hunt
Surveying and Engineering

C. NEWTON GOWDY, L.S. LICENSE NO. 39303
ROBERT W. HUNT, P.E. LICENSE NO. 043903

PAINTED POST, NEW YORK Job No. 40787 R

Figure 2.2-1 Valley Vista View No. 1 Wellsite plemented with a stimulation of the Marcellus. The funds necessary for this additional work were obtained by the postponement (probably cancellation) of the stimulation in another well, as reported hereinafter. In a scientific sense, it would have been very interesting to have been able to stimulate the Geneseo also.

The stimulation of the Marcellus confirmed the presence of an extensive fracture system by the way the well took the sand; it yielded a sustained open flow of 200 mcf/d, and a rapid build-up of pressure. Subsequently the lower part of the hole was plugged, and the second stimulation was performed in the Rhinestreet. This was a failure, yielding little more than water. The Rhinestreet perforations were therefore blocked, and the plug to the Marcellus drilled out (very carefully, because of the pressure below). The stimulation and the completion operations are summarized in the monthly reports of Appendix II 2.4, and listed in detail in the daily completion reports of Appendix II 2.5. The present physical configuration of the well is shown in Figure 2.2-2; the well connects to the upper Marcellus (the Oatka Creek) through the perforations, and to the lower Marcellus (the Union Springs) in the open hole.

Appendix II 2.6 is a compilation of the test results from the Marcellus. The calculated absolute open flow is 142 mcf/d; after stabilization, the expected initial production is 127 mcf/d against a line pressure of 250 psi. The gas is 81% methane, and its calorific value is 1016 Btu/cf.

At the time of writing, the well is shut in, awaiting connection to the Southern Tier pipeline. Only production will show whether the indicated initial flow can be sustained. If it is sustained, one possible interpretation is that the combination of natural fracturing and induced fracturing has yielded a very extensive fracture system in the Marcellus, with sufficient surface area between the fractures and the black shale to allow the gas to continue bleeding out of the shale steadily. If the production is not sustained, it may be that the extensive fracture system is in place, but that much or most of the Marcellus gas has already been lost, up fault planes, to the Nunda and to the surface. Or it may be found that the volume of the Marcellus is just not sufficient to sustain the production. Only time will tell.

VALLEY VISTA VIEW, INC. #1 WELL

MARCELLUS REOPENED

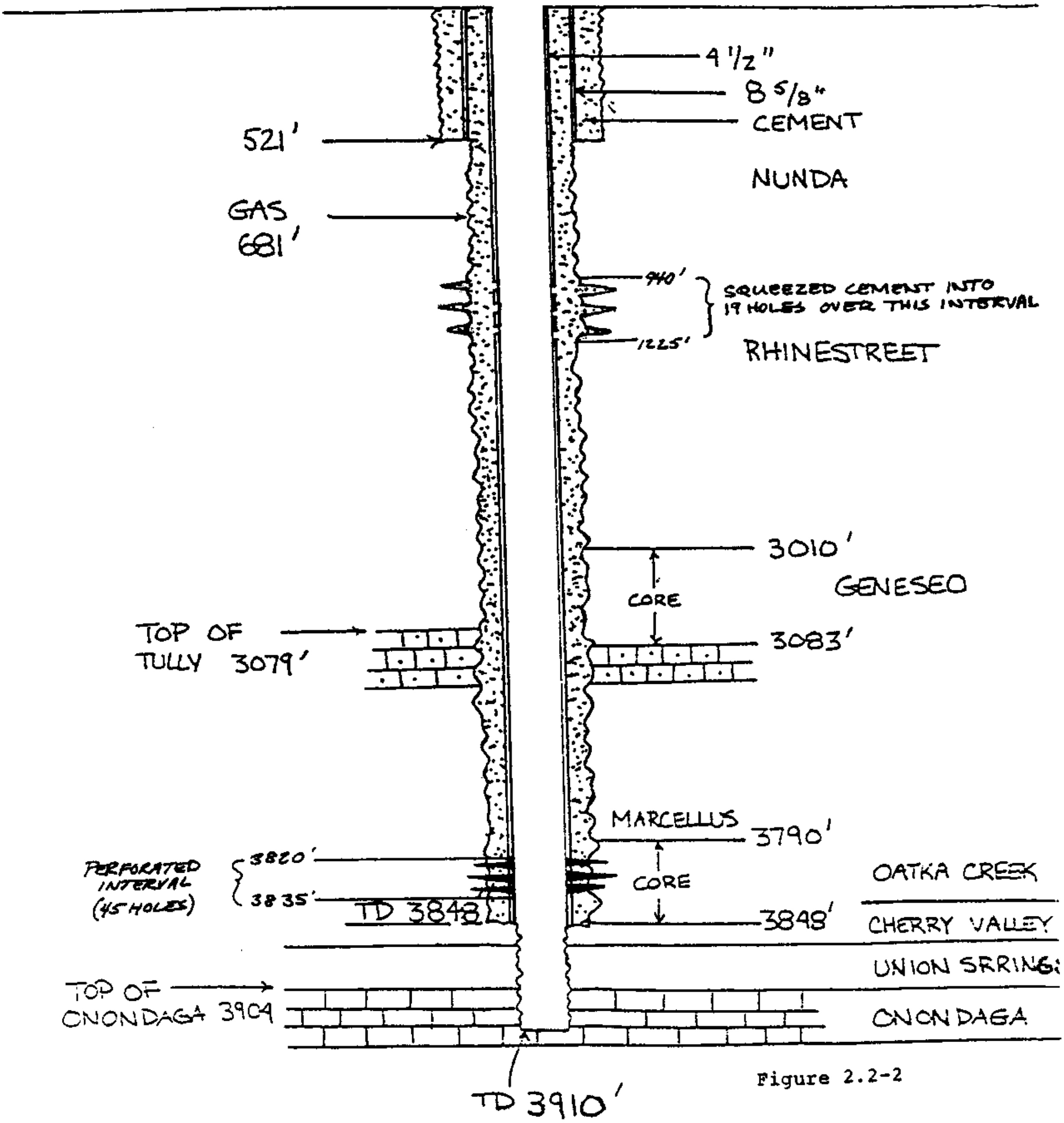


Figure 2.2-2

In retrospect, it seems likely that the gas obtained by the old-timers in the Rathbone field was not Rhinestreet gas (as they thought). Probably it was all Marcellus gas (perhaps supplemented by Geneseo gas) produced by drilling into fractures, or into silty units connecting to fractures. This is one explanation of the great variability in the initial production figures, and of the early death of the field.

2.3 THE DANSVILLE PROSPECT

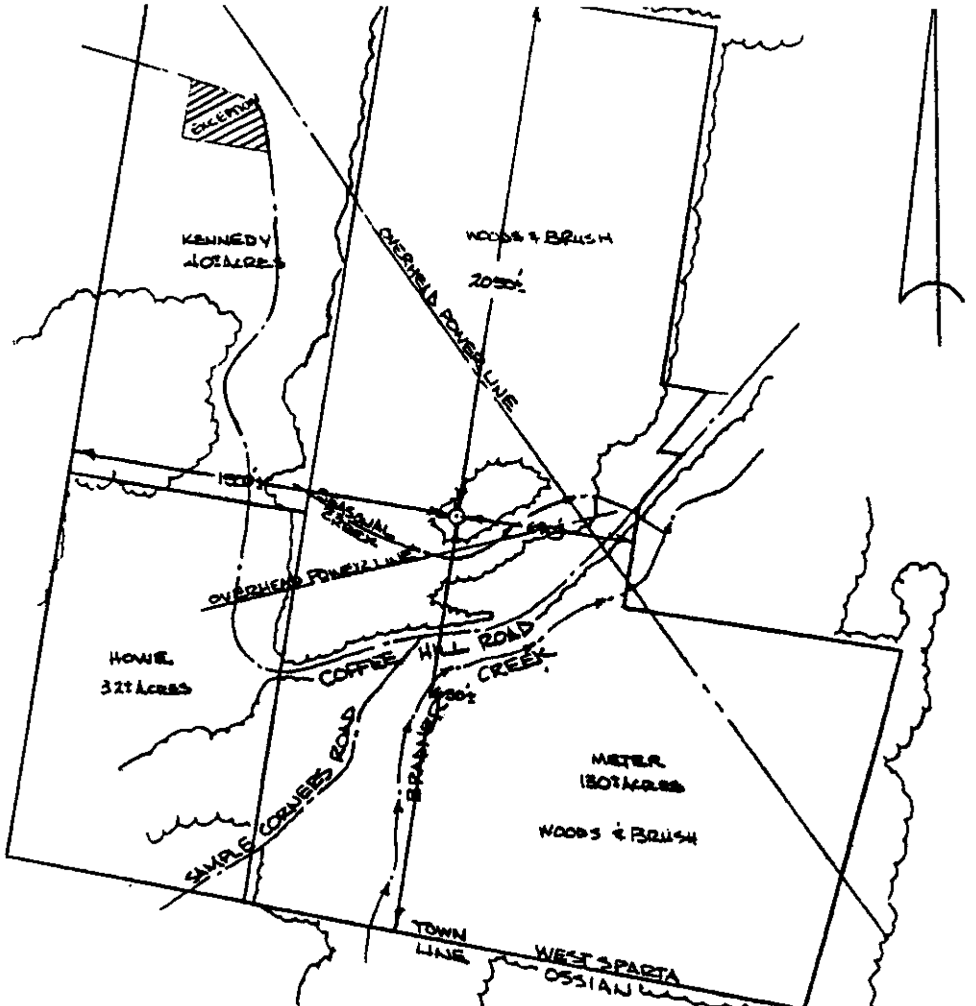
This was another test of the revitalization of an old shale-gas field. In this case, the old field has been ascribed to the Marcellus. Checks of the well depths revealed, however, that only two wells in the field actually went to the Marcellus; the other twelve (or so) terminated several hundred feet above. This old field is therefore ripe for revitalization in the Marcellus — particularly as the Marcellus is available at only 1600-1700 ft.

The exploration rationale for the well location is given in Appendix II 3.1; in fact the location was defined more by road construction and leases than by geological considerations. The well is called the Meter Kennedy Howe Unit no. 1; its location is shown in Figure 2.3-1.

The well was spudded on 6 September 1980. The daily drilling reports are given in Appendix II 3.2. Gas (plus nuisance-water) was encountered in the Geneseo; below the Tully there were several shows, culminating in a further show in the Marcellus. The density and sonic velocity were particularly low in the Marcellus, and the radioactivity particularly high.

In consultation with DOE, it was decided to stimulate the well in the lower Hamilton, including particularly the Marcellus. The stimulation and testing operations are summarized in the monthly reports (Appendix II 3.3) and described in detail in the daily completion reports (Appendix II 3.4). Figure 2.3-2 illustrates the present configuration of the well; the gas and water entry shown at 1017 ft is sealed off, of course, by the casing.

Appendix II 3.5 is a compilation of the test results from the Marcellus. The calculated absolute open flow is 95 mcf/d; after stabilization, the expected



NEW LOCATION: ☒
DRILL DEEPER: ☐
ABANDONMENT: ☐
REDRILLING: ☐
CONVERSION: ☐

A	B	C
D	E	F
G	H	I

SECTION KEY

COMPANY: ARLINGTON EXPLORATION COMPANY
ADDRESS: 137 NEWBERRY ST. BOSTON MA. 02116
LANDOWNER: METER, KENNEDY & HOWE
TRACT ______ ACRES: 202 LEASE NO. ______
WELL (FARM) NO. 1 SERIAL NO. ______
ANGLE OF DEVIATION, IF ANY: ______
ELEVATION 903'
LATITUDE 42°34'13" N
LONGITUDE 77°45'03" W
DISTANCE SOUTH OF NORTH: 19,900 AND
WEST OF EAST 200' IN SECTION: E
(See Key Above) OF OSSIAN QUADRANGLE
☒ 7.5 MIN ☐ 15 MIN MAP DATE 194[illegible]
TOWN [illegible] COUNTY: LIVINGSTON
SIGNED [signature] LS 49158
DATE [illegible] 30, 1980 SCALE 1" = 500'

NEW YORK STATE
DEPARTMENT OF
ENVIRONMENTAL CONSERVATION
BUREAU OF MINERALS

WELL LOCATION MAP

D.E.C. FILE NO ______

Gowdy and Hunt, P.C.

Surveying and Engineering

C. NEWTON GOWDY, L.S. LICENSE NO 39303
ROBERT W. HUNT, P.E. LICENSE NO 045903

JOB NO 42787 D

Figure 2.3-1 Meter, Kennedy, Howe Unit No. 1 Wellsite

DANSVILLE PROSPECT

METER, KENNEDY, HOWE UNIT #1 WELL

MARCELLUS OPENED

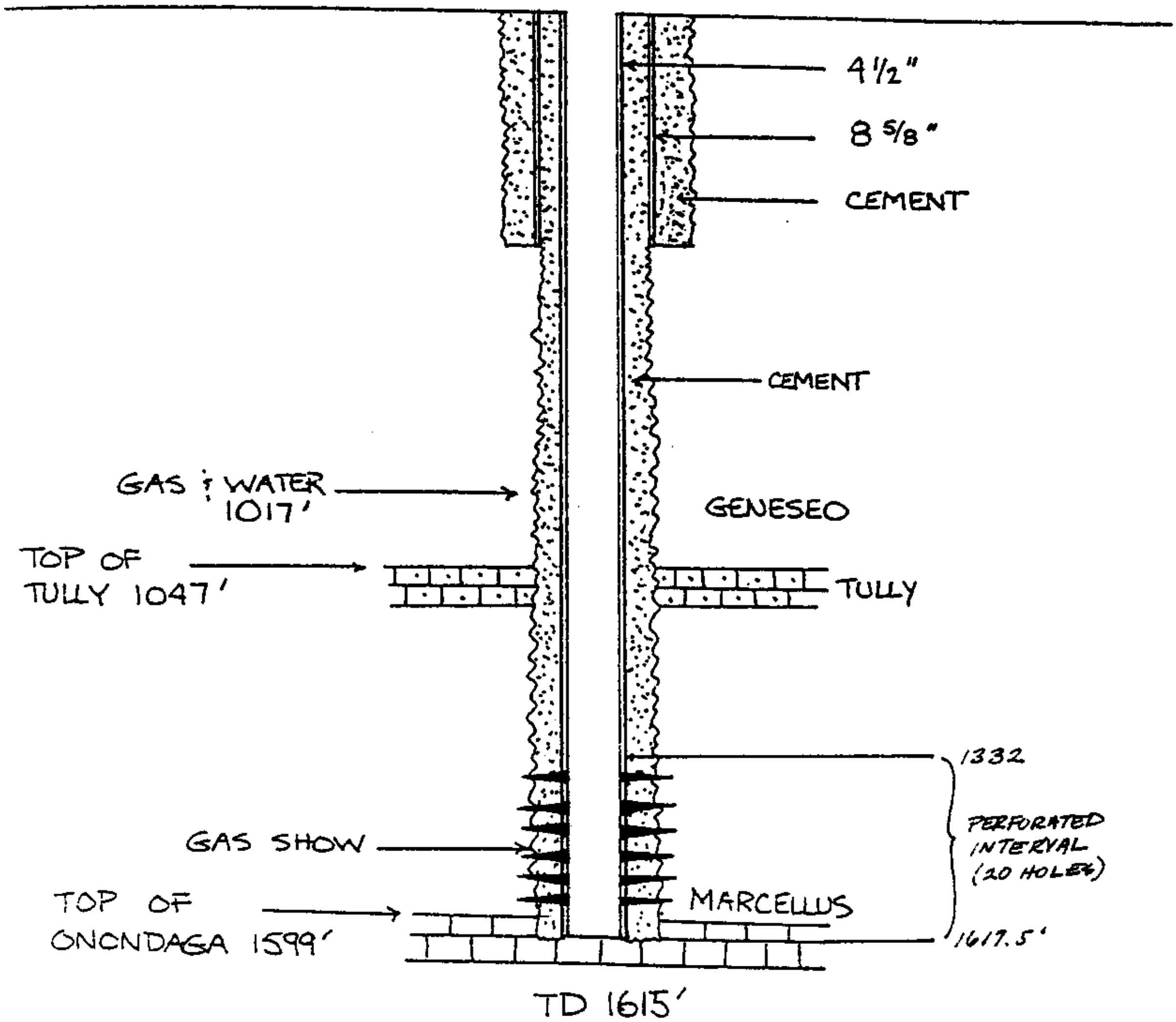


Figure 2.3-2

initial production is 60 mcf/d against a line pressure of 80 psi. The gas is 80% methane and unusually rich (12%) in ethane; its calorific value is 1134 Btu/cf.

At the time of writing, the well is shut in, awaiting connection to Consolidated's line.

If the production from this well is sustained, its shallow depth should make it clearly economic. The Marcellus appears to be very organic-rich, and the existence of gas in the Hamilton above the Marcellus adds to the interest; it may be that fractures or other conduits in the Hamilton are collecting gas from a wide area of the Marcellus, and this would be a very satisfactory situation.

At this stage, there is no indication whether there is anything special about the area of the old Dansville field, or whether the same favorable circumstances extend further. By the same token, there is no present evidence as to the geological origins — structural, tensional, depositional — of these favorable circumstances.

2.4 THE NORTH CORNING PROSPECT

This well was designed to test the possibility that a gas conduit (of the type discussed in Part 1, Part 1, section 1.3.5) exists in the Corning area.

The evidence for this conduit lay in reports of gas shows from four (later six) wells, all at the same stratigraphic level within the Rhinestreet shale. On the logs of the wells there was no indication of a sandy or silty unit at the depth of the shows, and so it was hypothesized that the conduit was a fractured or rubbleized zone extending almost horizontally. The dissipation of overpressure in a rapidly-deposited shale layer was cited as one plausible explanation for this zone.

Appendix II 4.1 gives the exploration rationale for the well location. The well was spudded on 21 July 1980, as the Scudder no. 1. Appendix II 4.2 summarizes the drilling process, and the detailed drilling reports are given in Appendix II 4.3.

Only a very minor show of gas was encountered at the depth of the expected conduit. Further, a core straddling this interval (while showing multiple coring-induced fractures) showed no evidence of a conduit visible by field inspection. Accordingly the well was left uncased, and shut in pending the results from the next well (the Erwin prospect). Figure 2.4-1 shows the present configuration of the well.

The core analysis by Cliffs Minerals (separate report to DOE) showed that the shale is unusually free of fractures. However, the three natural fractures which were present were near the expected depth of the conduit, and there was a clear trend for the coring-induced fractures to be concentrated in this zone also; the latter fact suggests that there is indeed a weakness in the shale at this depth, parallel to bedding. The tentative conclusion, then, is that there is an anomalous layer at this level, that at neighboring wells (where it is more open than at the Scudder well) it could conceivably account for the gas shows observed, but that at the Scudder location it is insufficiently developed to yield significant gas.

There is a possibility that the horizontal layer could be opened by a suitably-controlled stimulation procedure, and that it might thereby be extended to intersect one or more of the known fault planes to the north. However, the generally "dead" nature of this well is taken as downgrading this possibility, and it is unlikely that the well will be stimulated. Indeed, in the light of the better success in the Marcellus at other locations, it seems that the best use of the existing hole would be to deepen it to the Marcellus.

The funds released by the elimination of casing and stimulation costs in this well permitted the deeper (Marcellus) stimulation in the Rathbone well; on present evidence this was clearly a better use of the money.

2.5 THE ERWIN PROSPECT

This well, west of Corning, was also designed to test the conduit — but in a location believed to be close to a major down-to-the-south fault. The exploration rationale is given in Appendix II 5.1, and the well location in Figure 2.5-1.

NORTH CORNING PROSPECT

AMBROSE E. SCUDDER # 1 WELL

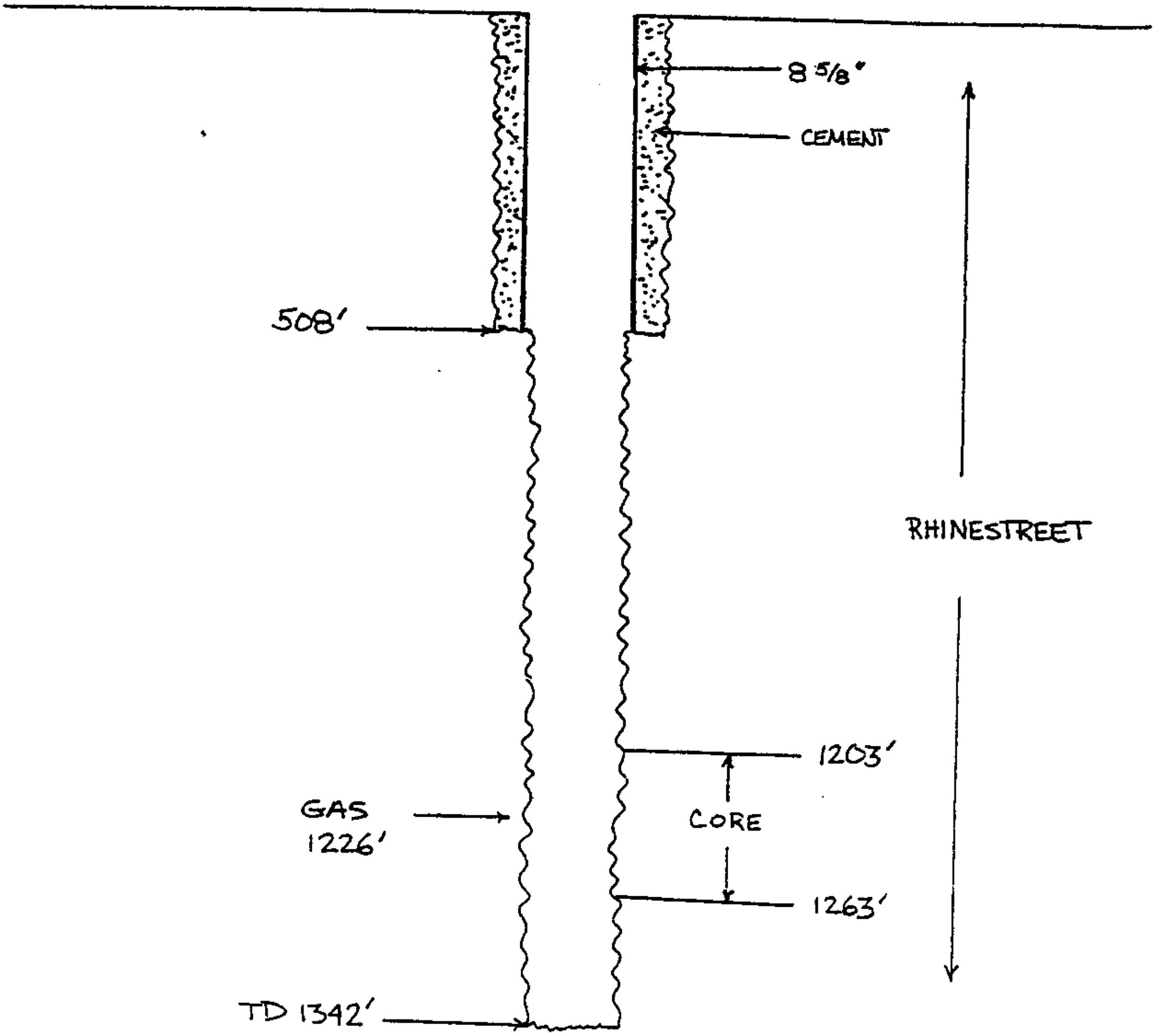


Figure 2.4-1

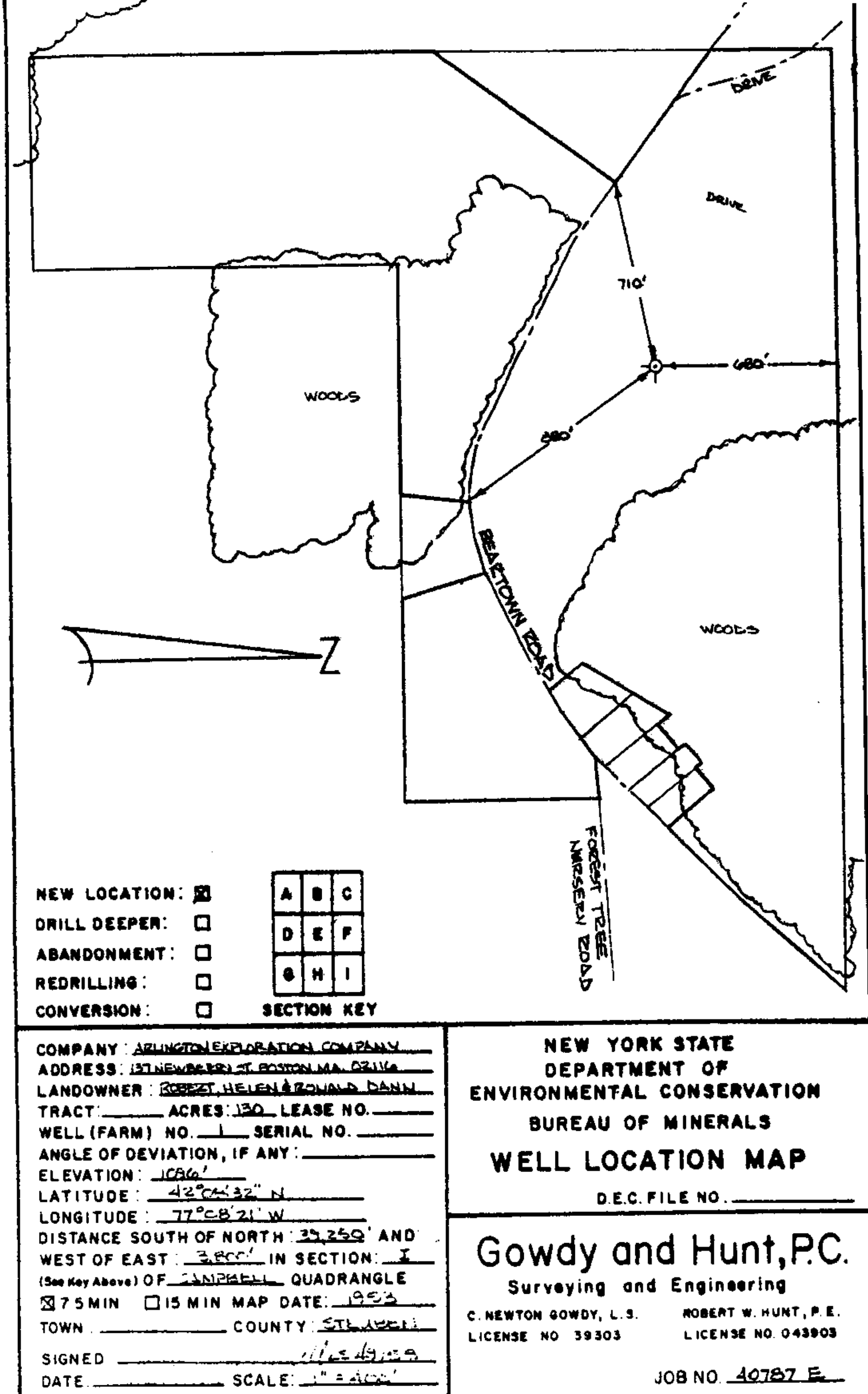


Figure 2.5-1 R. Dann et al No. 1 wellsite

The well was spudded on 28 July 1980, as the Dann no. 1. Appendix II 5.2 summarizes the drilling progress, and Appendix II 5.3 gives the daily drilling reports. The well was an example of some of the difficult conditions which can sometimes occur near the surface, when drilling in glacial detritus.

Gas was encountered at the expected depth of 1074 ft; the initial flow was 270 mcf/d.

After measures to limit the flow of water into the hole, the well was connected to a nearby line and produced for 25 days. The object in this was to test the economics of shale-gas production <u>without</u> stimulation. However, the actual production (against a low back-pressure) was very small, and so the stimulation was undertaken as planned. Appendix II 5.4 summarizes monthly progress, and Appendix II 5.5 gives the daily completion reports. Figure 2.5-2 shows the present configuration of the well.

The well tests are given in Appendix II 5.6. The calculated absolute open flow is only 10 mcf/d. After these tests the well was put back into production; unfortunately the gas still contained considerable nitrogen from the stimulation, and this had embarrassing consequences to the local pilot-lights. It is believed that further venting has now disposed of the nitrogen, and the well is again flowing into the line for a 60-day test period. Although the gas volume is small, the opportunity to produce the well is very desirable; while the mechanism of gas production (and the nature of the conduit) remain so poorly understood, all experience is beneficial. Further, there does remain a slim possibility that the removal of water from the formation will gradually allow improved production.

The latest analysis of the gas shows 86% methane, and a calorific value of 1021 Btu/cf.

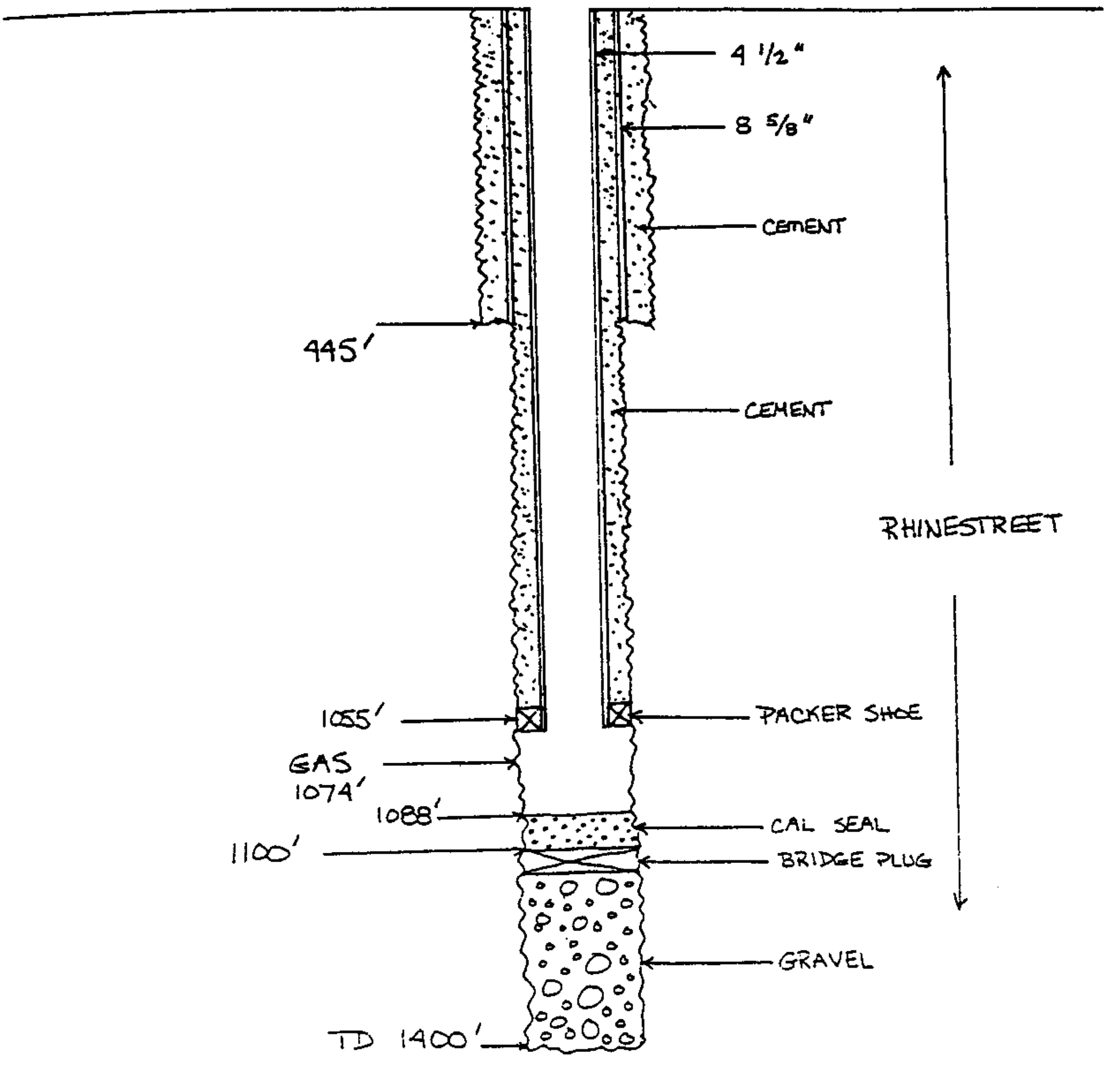
It remains to ask whether the search for conduits is a good exploration rationale. To be attractive, a conduit layer must be able to <u>transmit</u> considerable gas, and must connect to a fracture system capable of <u>supplying</u> considerable gas. The first is a function of its thickness and permeability; the second suggests

ERWIN PROSPECT

ROBERT M. DANN #1 WELL

RHINESTREET OPENED

Figure 2.5-2



that the conduit must intersect a near-vertical fault or fracture system extending down into the organic-rich shale below (while remaining sealed above).

In the Corning area, the gas shows in the old wells are very narrowly defined, and this confirms the message of the Scudder core that the conduit is no more than a foot or two thick. Further, the conduit permeability at the Scudder location was obviously negligible, with the result that the Scudder well was a failure. At the Dann well, however, the initial flow suggested much better local permeability, though the narrow definition of the gas zone again indicated a thin layer. (It was unfortunate, of course, that the core was taken in the Scudder well, and not in the Dann. The laws of Murphy again.)

It is not known exactly how far the Dann well is from the fault plane feeding the conduit. Because of this, it is not known whether the rapid initial decline to small flow represents inadequate permeability or thickness of the conduit, or a long transmission distance, or poor supply at the other end. The cautious conclusion at present is that if the present small production is maintained, it may just be worth determining the fault location more precisely, and drilling a well closer to the fault.

However, at the present state of knowledge, and other things being equal, the appeal of an 1100-ft well to an imperfectly-understood conduit near Corning can scarcely compete with that of a 1600-ft well to the rich Marcellus near Dansville.

EXPLORATION RATIONALE
RATHBONE PROSPECT
VALLEY VISTA VIEW INC. #1 WELL

1. Our attempts to establish the details of the old gas production have yielded contradictory maps and well assessments. After reviewing all the evidence available, we have constructed Map 1 (2000 ft to 1 inch) as the best that can be done. Generally this accepts the Consolidated Gas map of 1933. For the well production figures we can do no better than accept Art Van Tyne's notes from the memory of an old timer now dead; the estimates of gas production were not actual measurements, and must be treated as uncertain.

2. For some wells the estimates of production are linked to depth figures, while for others they are not. Generally the figures allow separation of the producing intervals into three ranges, centered on approximately 550 ft., 350 ft. and 175 ft above sea level. Maps 2, 3, and 4 suggest the reported production for these three ranges by the area of the black discs. Wells which do not penetrate a range are omitted from the corresponding map; wells which penetrate but for which no imformation is avialable are marked with a ?.

3. The most prolific depth range is the deepest (Map 4); the initial production reported for the best well (the largest disc) is 2000 mcf/d.

4. We have purchased a seismic line which runs generally north-south, some 2 miles to the west of the field. Features evident on this line include:

- the eastward termination of the structural uplift associated with the Jasper field;
- a small graben at Onondaga level, to the south of the uplift; this graben appears only very slightly at Tully level; and
- a down-to-the-south flex occurring at all levels, to the south of the graben.

The flex passes just north of the village of Hedgesville, and substantially coincides with a steep hill. There is therefore a risk that the flex is not real, but is caused (in whole or in part) by inadequate static corrections. Here we accept that the flex is real. If so, it represents a likely cause for a fracture system; we would expect tensional fractures to open up just to the south of the up-side of the flex.

5. For this to be useful, we need to know which way the flex goes. The best solution is to search for the same feature on another seismic line, which follows the river valley to the north and east of the field. This line is advertised as available by the seismic brokers, but our attempts to buy the line have not been successful. The problem is that the line is owned by a group including Columbia, and Columbia (having active prospects at deeper levels in the area) have so far refused to release it. We are hoping that our present farmout relationship with Columbia will allow us to reverse this decision.

6. For the present, all we can do is to assume that the bearing of the flex is the same as that of the general fault grain established from well control in the Jasper field. This is about 65° east of north. Projecting the flex in this direction leads to a flexed zone as shown on Map 5 (which is otherwise a reproduction of Map 4). The correlation of the good production with this zone looks almost too good to be true. Map 6 shows <u>all</u> initial-production estimates from all levels (including that of a shallow well to the west) in relation to the projection of the flex.

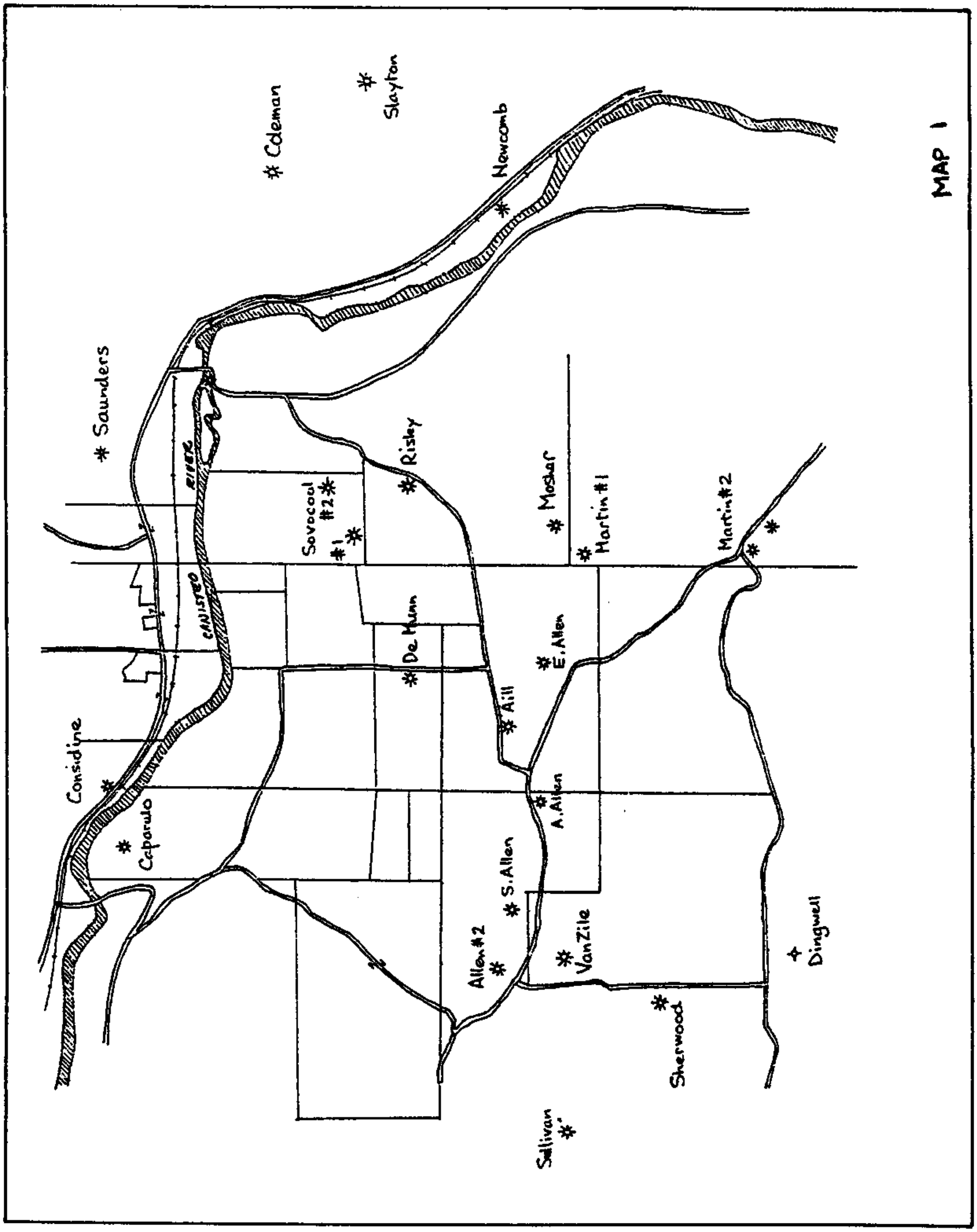
7. Map 7 superimposes the lineaments identified by Dr. Howard. The heavy line is a lineament traced from satellite imagery; the lighter lines are from aerial photographs. The best well location does correspond to a lineament intersection; for the rest, the significance of the lineament picture is unclear.

8. Our first preference for the new well location is in the fairway represented by the flexed zone. However, we have not been able to secure a farmout from Columbia in this fairway. Columbia are prepared to farm out only the region hatched in Map 8, and the furthest south we can drill is therefore 660 ft from its southern boundary. The location chosen is shown as VVV No. 1; this has been selected as a compromise between distance from the flex, cost of access,

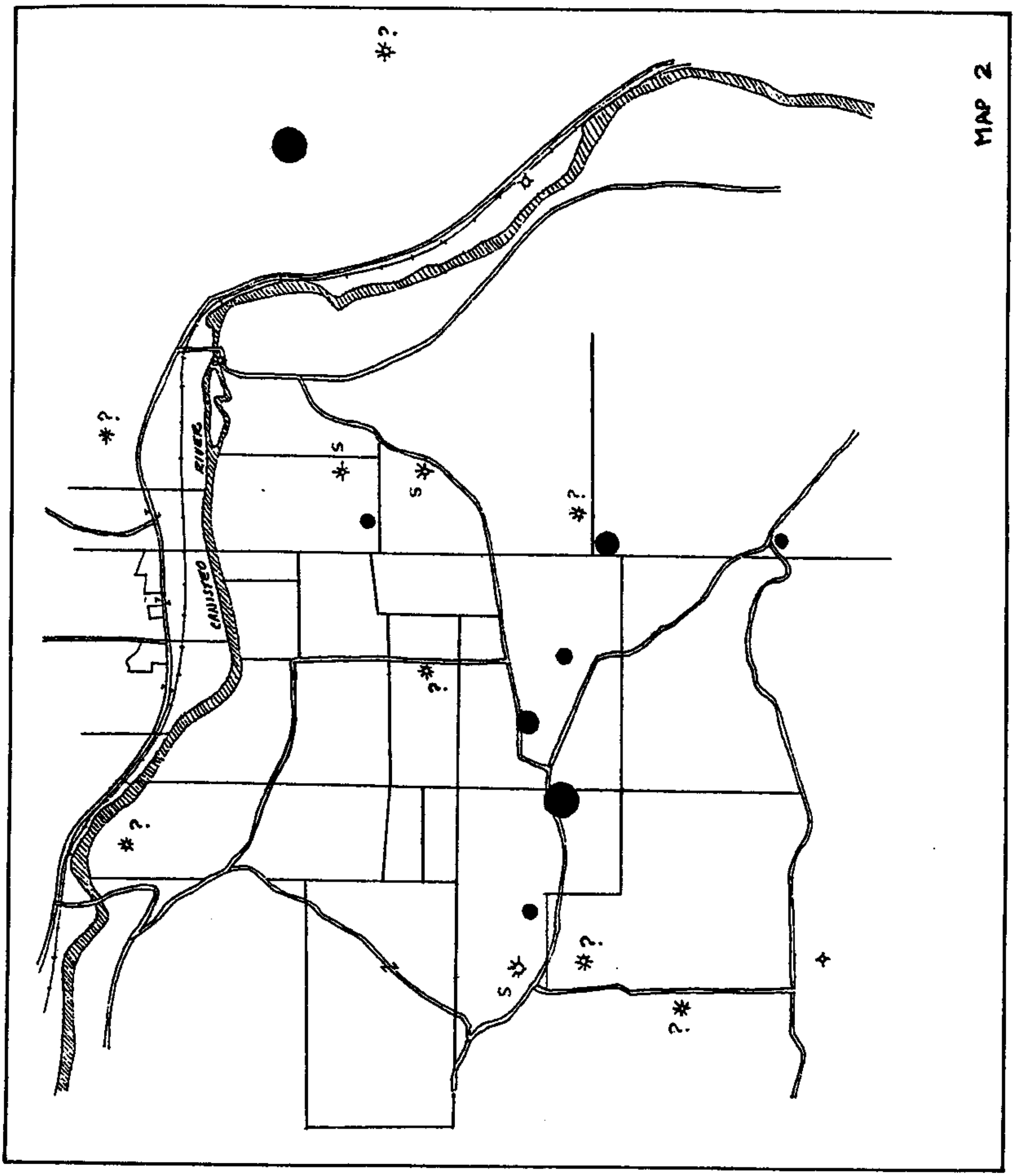
and separation from the rather less successful well to the east.

9. It follows that we do not expect the new well (at least at the Rhinestreet level) to yield natural flow to rival the best of the old wells. However, the old wells declined rather rapidly (confirming the conclusion that they penetrate a highly fractured zone). The location selected does seem very reasonable as a test of the ability of modern stimulation techniques to revitalize old shale-gas fields, and this, we recall, was the original rationale for the Rathbone well.

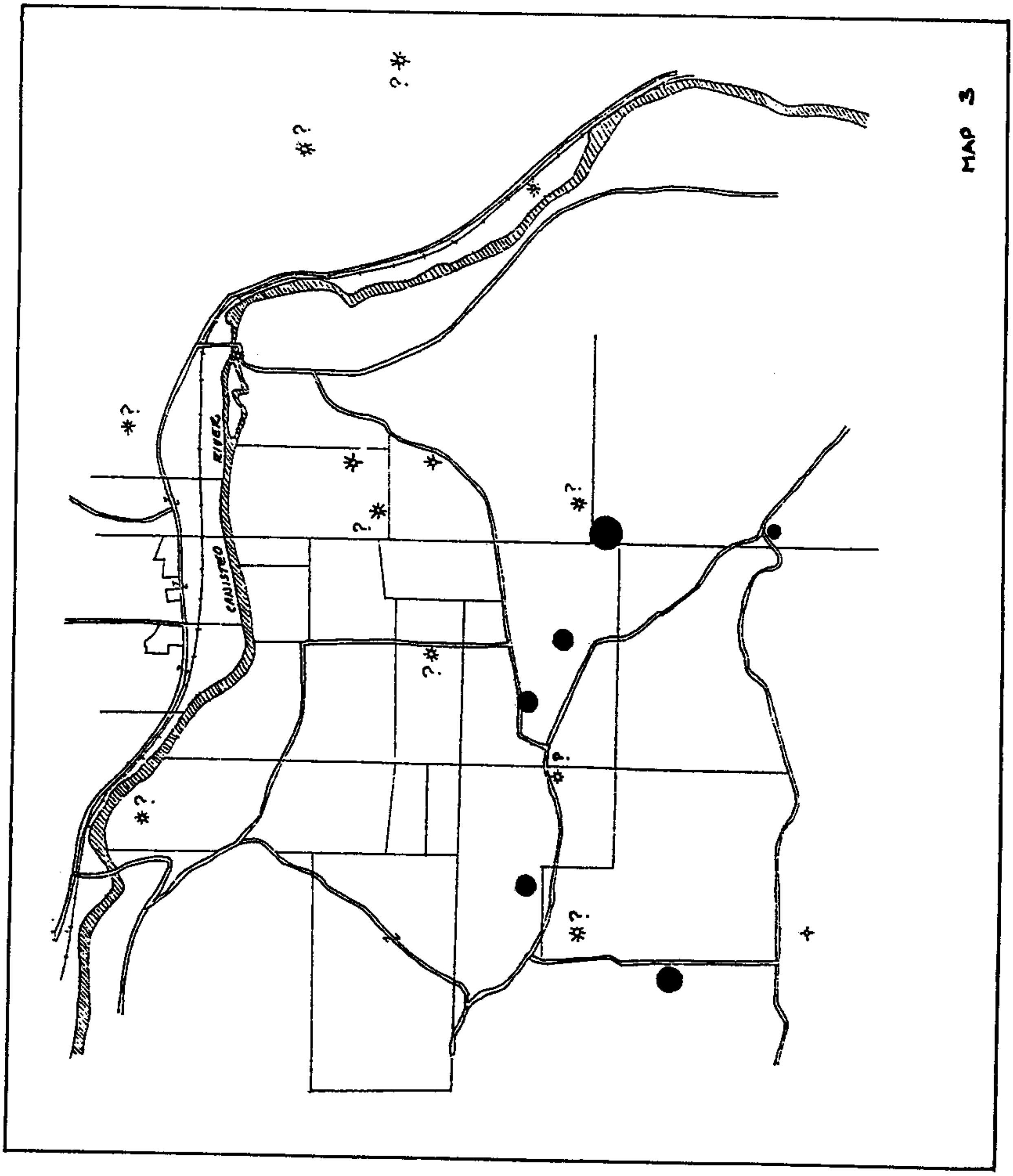
10. Since the seismic indications are that the flex exists down to Onondaga level, the new well also has a good chance of encountering the beginnings of fracturing in the Marcellus.



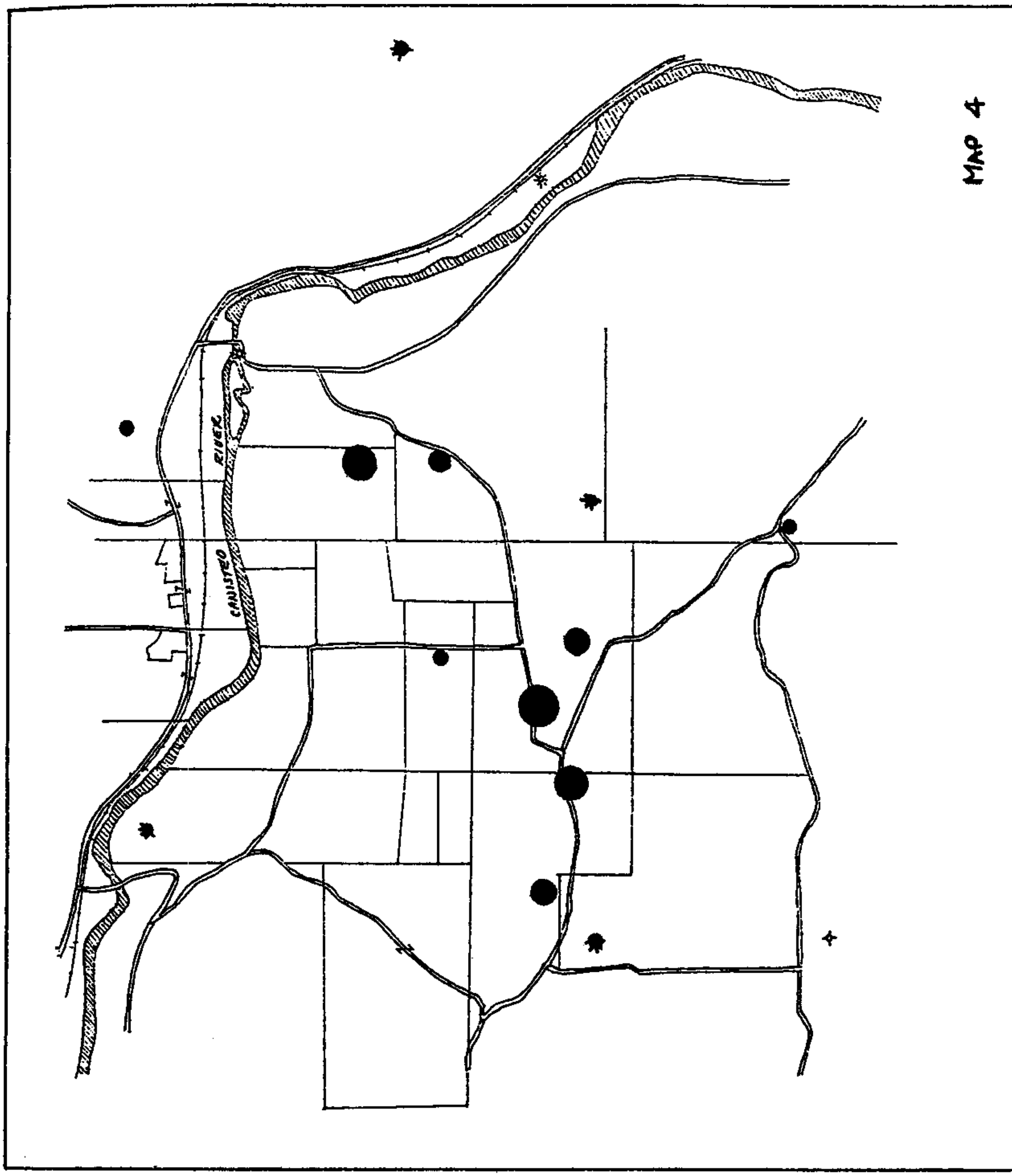
The Rathbone shale-gas field: old wells.



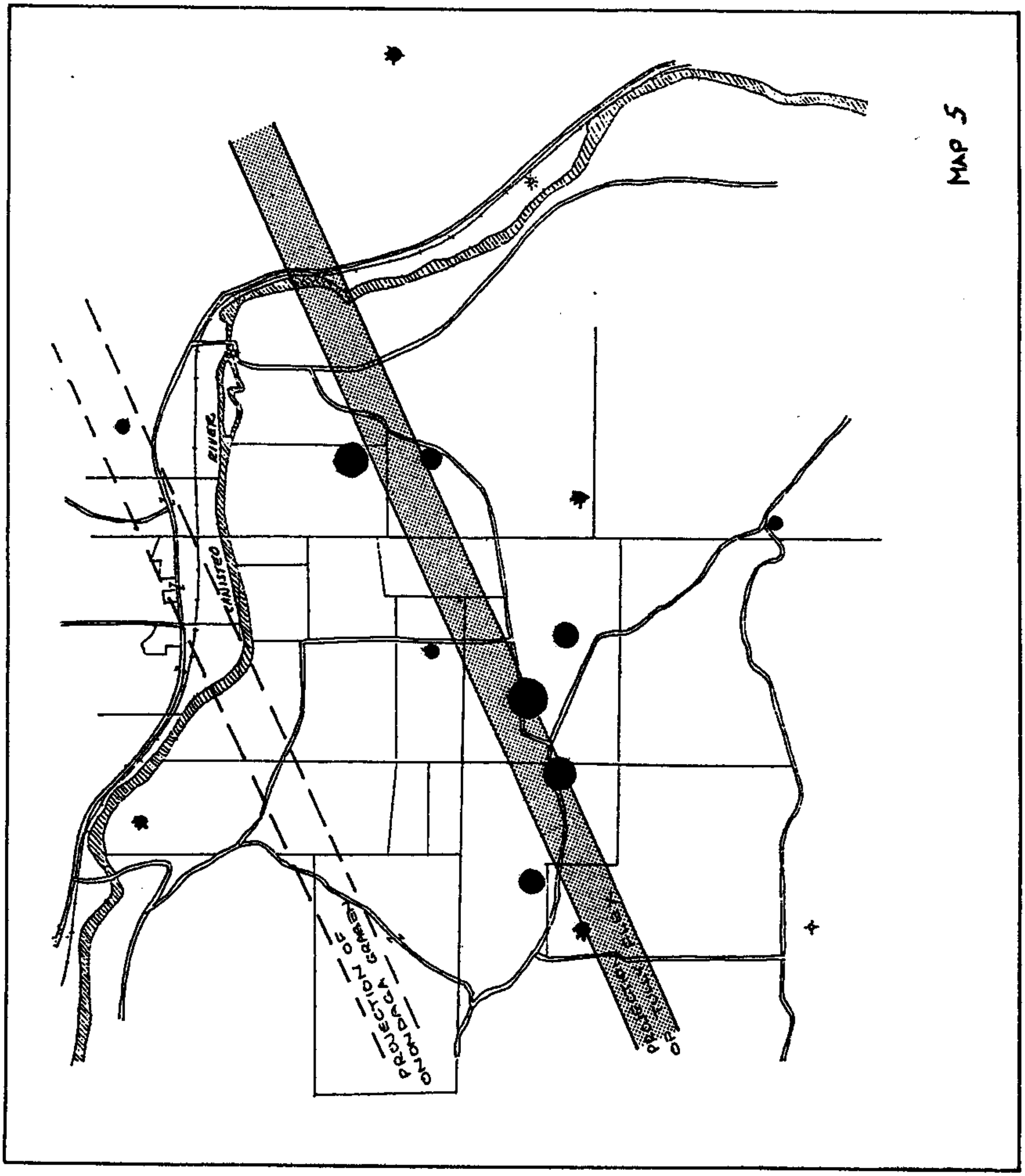
The Rathbone shale-gas field: reported initial production, shallow range.



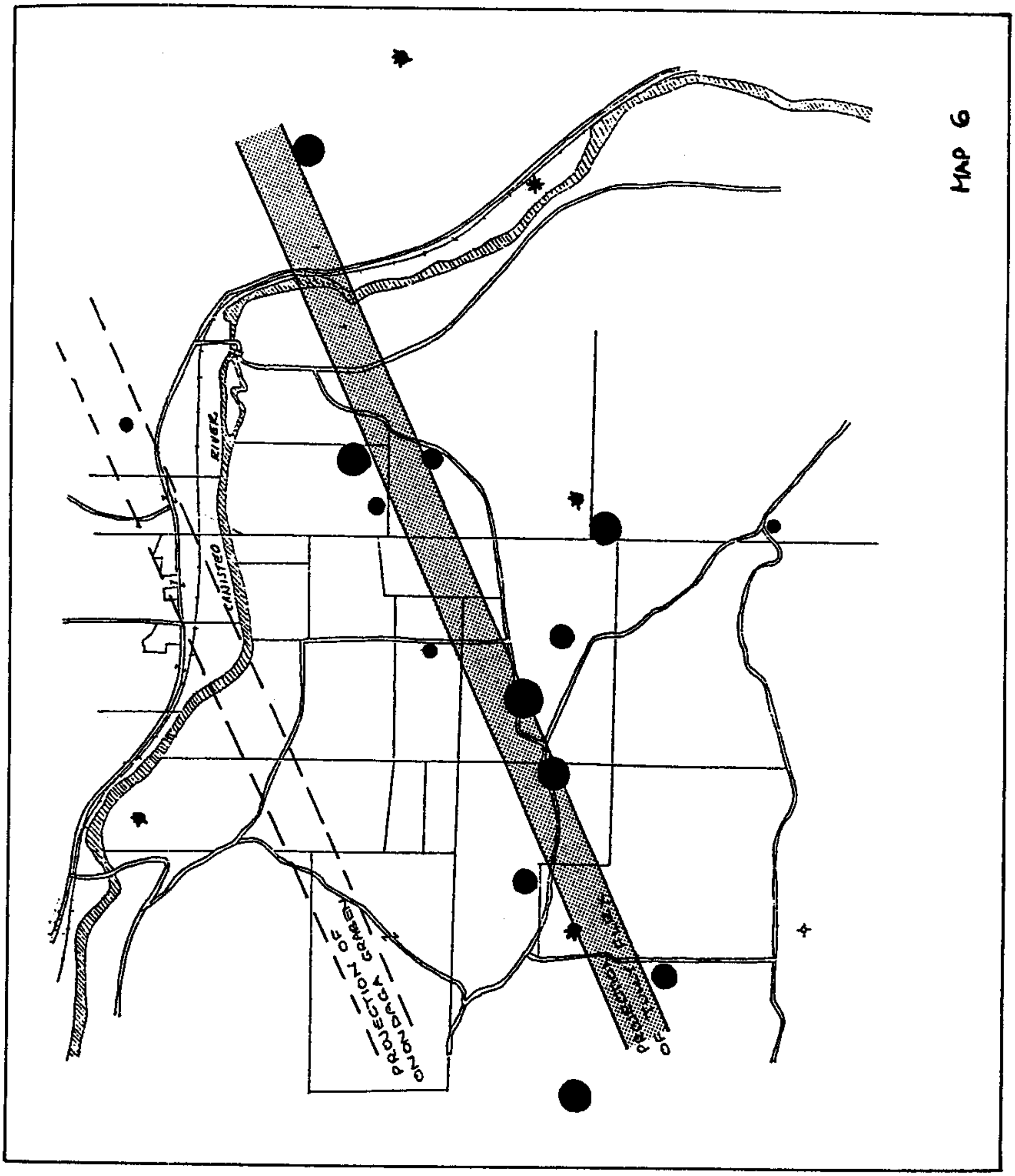
The Rathbone shale-gas field: reported initial production, middle range.



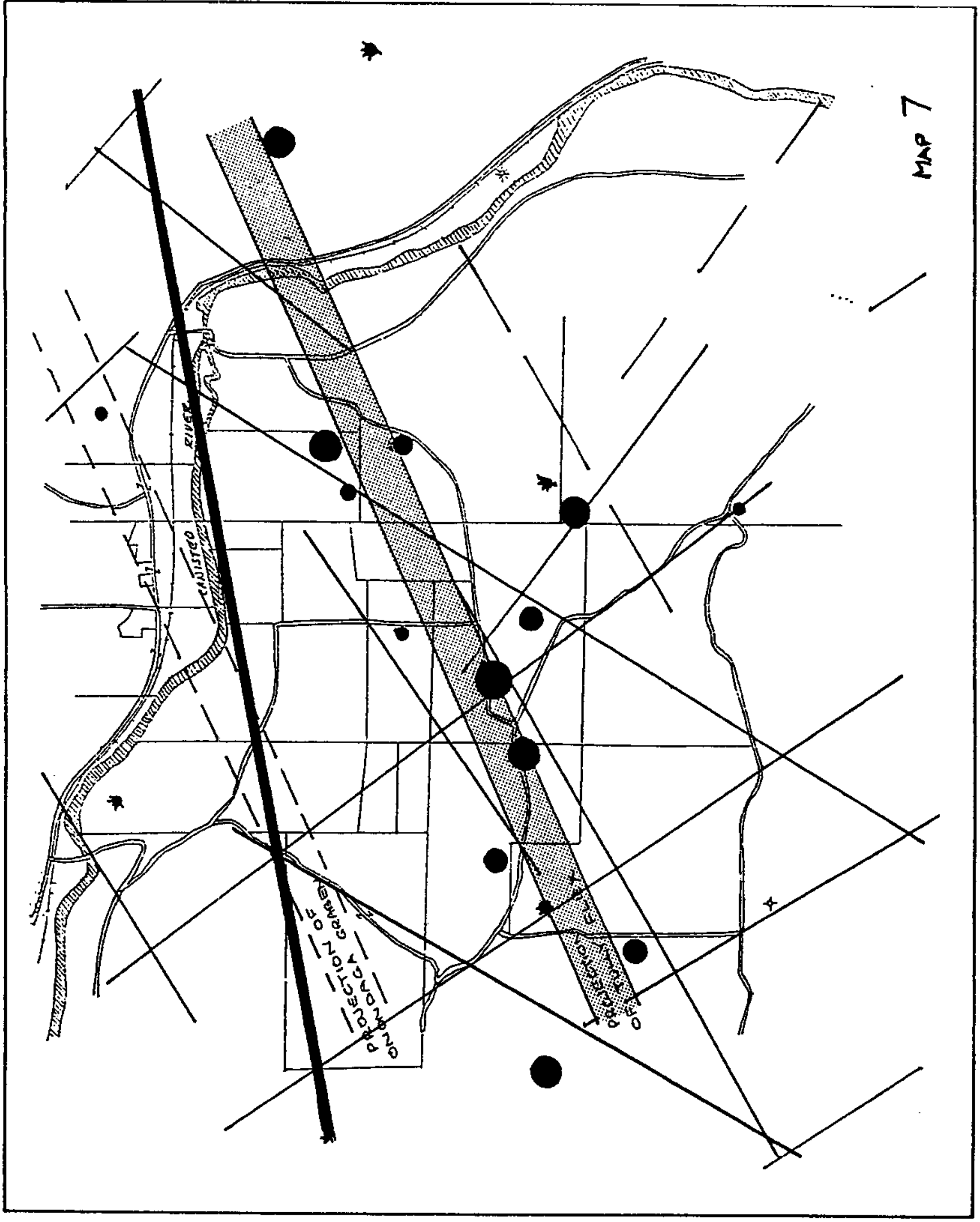
The Rathbone shale-gas field: reported initial production, deep range.



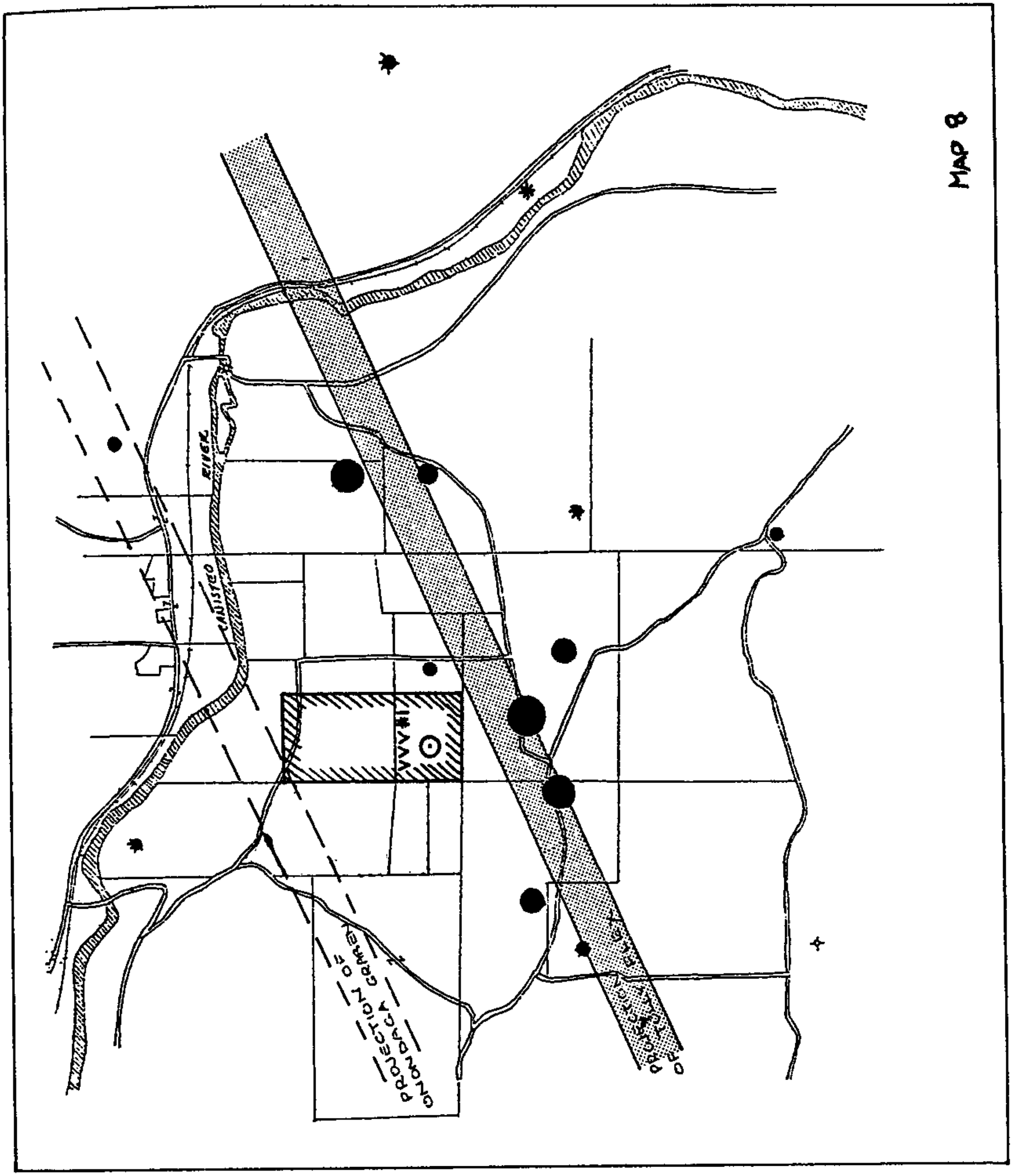
The Rathbone shale-gas field: addition of flexed zone (projected from west) to map 5.



The Rathbone shale-gas field: flexed zone superimposed on all production.



The Rathbone shale-gas field: Dr. Howard's lineaments superimposed on map 6.



The Rathbone shale-gas field: location of Valley Vista View no. 1 well.

COMPILATION OF MONTHLY REPORTS
RATHBONE PROSPECT
VALLEY VISTA VIEW INC. #1 WELL

July 31, 1980

Rathbone: Valley Vista View No. 1

This well was spudded, at the location given in the monthly report for June, on 21 July 1980. A small show of gas was encountered during the drilling of the surface hole, and substantial gas at about 680 ft. The gas was gauged at about 1300 mcf/d on both 23 and 24 July.

Since any increase in the gas flare would have constituted a fire hazard, drilling was suspended until further clearing of the surrounding trees could be accomplished. About 16 hours of rig time was lost on this account.

Drilling then proceeded normally, with the gas continuing to be flared. The shallow gas had blown down to about 400 mcf/d by 26 July, and to perhaps half this by 27 July; it may continue to decrease, to unimportant levels.

In the Rhinestreet (the primary target) the mudlogger recorded 1100 gas units, from a background of 500 units, at 1838 ft.

Drilling continued to 3010 ft, where the first core was started. The Tully was encountered at 3079 ft, and the coring was stopped 4 ft into the Tully. Thus a good core of 69 ft of the Geneseo was obtained; the shale is black, fractured, and bleeding gas. At 3076 ft, 3 ft above the Tully, the mudlogger recorded 155 units against a background of 5 units.

Drilling continued to 3790 ft, where the second core was started. The Onondaga was encountered at 3844 ft, and the coring was stopped 4 ft into the Onondaga, at TD. Thus a good core of 54 ft of the Marcellus was obtained. The total core, over both intervals, was 131 ft.

The suite of dry-hole logs was run. In addition to the shallow gas, numerous indications are reported on the noise log in the Rhinestreet (though none at 1838 ft), and one in the Geneseo. Liquid was encountered at 3070 ft, and it is believed that the shallow gas interval is making significant water.

Production tests are now in progress on the well.

The nature of the shallow gas accumulation is not yet clear. It is hoped that the wet-hole logs will indicate whether it represents the Nunda, or a confluence of fractures.

August 31, 1980

Rathbone: Valley Vista View No. 1

After the natural-flow tests of last month's report, the well was filled with KCl water and the wet-hole logs were run. As usual with the shale wells, the logs contained their own enigmas; none of the logs, for example, showed any definable anomaly at the level of the shallow gas show. Therefore, this shallow gas may be derived from a fracture system connecting into the well bore, rather than from the Nunda or some other stratigraphic interval.

The well was cased, and cemented in two stages; it is now awaiting the formulation and approval of a stimulation program. Several levels are candidates for treatment. The Marcellus core was seen to be fractured and bleeding gas; the logs show low density and very low velocity. The Geneseo core was also fractured and bleeding gas; the logs are again favorable, with much cycle-skipping and some sibilation. The Rhinestreet, which was the primary target, shows at least five sibilation anomalies over a 300 ft. interval, and cycle-skipping over this interval and others. And even the shallow zone cannot be discounted if it does indeed connect into extensive vertical fractures. Since this situation has some analogy to the Schockling well in Ohio (where separate stimulation programs are being conducted at three levels), we shall make a proposal for the Rathbone well after the experience of the Schockling well.

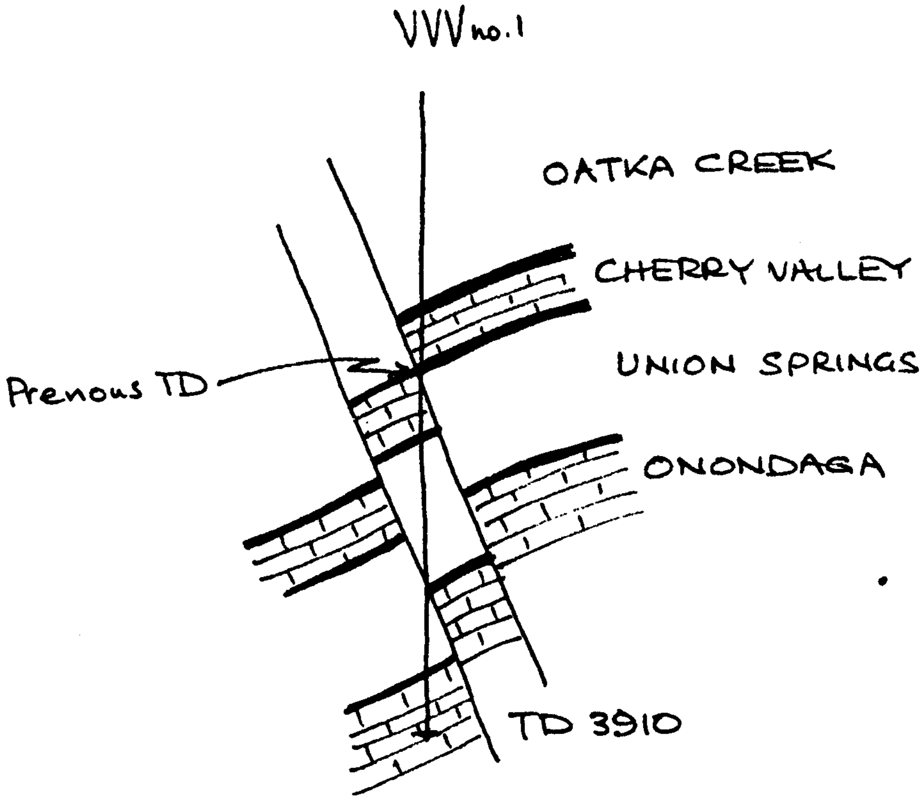
In last month's report, on the basis of the core description, we accepted that the well had penetrated the Union Springs (the lower Marcellus) and bottomed in the fractured Onondaga. The subsequent wet-hole logs throw some doubt on this. We have made an extensive analysis of all the information available from the core, the logs and the driller's records; our tentative conclusion is that the well probably bottomed in the Cherry Valley, a few feet short of the Union Springs. Recognizing the risk of penetrating through the Onondaga if this is not so, we presently plan to deepen the well by approximately 20 ft; this can be done, conveniently, as a continuation of the operation of drilling out the 30 ft of cement presently in the bottom of the hole. We expect that the final picture will show a disturbed zone in the Marcellus, with a significant local thickening in the Oatka Creek (probably associated with dip into the flex) and extensive fracturing and movement in the Cherry Valley, Union Springs and Onondaga.

September 30, 1980

Rathbone; Valley Vista View No. 1

As projected in the report for August, the well was deepened to the Onondaga, and encountered extensive faulting in the intermediate formations. The logs suggest the interpretation of the attached sketch, with almost twice the expected thickness of both Cherry Valley and Union Springs. From the point of view of natural fracturing in the Marcellus, the well location was superb; this perfection of location was fortuitous, of course. It remains to be seen whether — as is certainly possible — the zone is so fractured that substantially all Marcellus gas has escaped upwards (some being lost, and some probably trapped in the shallow reservoir encountered at 680 ft).

In a meeting with C.A. Komar and K-H Frohne of DOE, it was agreed and approved to perform two separate stimulations of the well; one in the Marcellus, and one over an extensive iterval in the Rhinestreet. The Marcellus stimulation will be performed on October 27; NYSERDA personnel may be interested to observe it.



Sept. 1980

Possible fault interpretation of VVV no. 1 logs.

DAILY DRILLING REPORT
VALLEY VISTA VIEW, INC. #1

7-22-80: Presently drilling at 130'. Moved in and rigged up Delta Drilling Company's rig #91. Spudded the well at 3:00 pm, 7/21/80. Ran 19' of 11 3/4" conductor pipe and set at 17'.

7-23-80: Presently waiting on cement. Drilled to 521'. Ran 510' of 8 5/8" surface casing and set at 521'. Cemented with 100 sacks. Good cement returns.

7-24-80: Presently shutdown at 681' due to gas flow. Drilled out under surface. Encountered significant gas flow at 681'. Gas flow tested at 9:30 pm on 7/23/80 and measured 1.3 MMCFD.

7-25-80: Presently drilling at 2058'. Had dozer expand location to accomodate gas flare. Gas flow tested at 10:00 am on 7/24/80, and measured 1.3 MMCFD with some water. Mud logger noted gas increase at 1838'.

7-26-80: Presently drilling at 2950'. Gas flow tested at 11:30 am 7/25/80, and measured 400 MCFD with some water.

7-27-80: Presently coring at 3035' (Geneseo). Drilled to 3010'. Came out of hole, rigged up core barrel and went in hole with core barrel. Started coring at 2:45 am, 7/27/80.

7-28-80: Presently drilling at 3214'. Retrieved 1st core at 2:15 pm, 7/27/80. Started back in hole at 3:00 pm, 7/27/80. Cored to 3083'. Retrieved 2nd core at 12:30 am, 7/28/80. Top of Tully 3079'. (Total cored interval 3010'-3083').

7-29-80: Presently coring at 3797'. Drilled to core point at 3790'. Came out of hole, rigged up core barrel and started coring at 4:35 am 7-29-80.

7-30-80: Presently rigging up wellhead for build up/drawn down test. Cored to 3848'. Core out of hole at 4:30 pm, 7/29/80. Cored interval 3790'-3848' with good recovery. Top of Cherry Valley at 3844'. Driller's TD 3848'. Ran Birdwell's gamma ray, density, temperature and sibilation logs. Logger's TD 3828' (40' of fill up in hole due to sluffing shale). Gas shows noted on the sibilation log at 540, 552, 598, 600; numerous shows in the Rhinestreet and show in the Geneseo. Top of Tully at 3076'. Found liquid level at 3070'.

7-31-80: Presently shut in for pressure build up test. Well shut in 10:30 am 7/30/80. 80 psig at 7:30 am, 7/31/80 (21 hrs.).

8-1-80: Presently rigging up Schlumberger to run wet hole logs. Shut in pressure of 85 psig at 11:30 am (25 hrs.). Ran draw down test as follows:

	Started Test	Finished Test	Total Hours	Choke Size	Started Psig	Finished Psig	Flow Rate
7-31-80:	11:30 am	1:30 pm	2	1/4"	85	11	32 MCF/D
	1:50 pm	2:50 pm	1	1/2"	11	5	78 MCF/D

Loaded hole with 2% KCL water. Went in hole with drill pipe. Circulated and cleaned out hole to TD.

8-2-80: Presently rigging up to run 4 1/2" casing. Ran Schlumberger wet hole logs in 2% KCL water. Ran gamma ray, neutron, density, induction and sonic. Tripped in hole to check TD. Found no fill up. Laid down drill pipe.

8-3-80: Well behind pipe and cemented. Ran 3839' of 4 1/2", 10.5 lbs casing, set at 3848' (tagged bottom at 3853'). DV packer collar set at 2927'-2930'. Cemented first stage with 200 sacks of "Thix-set," 2% calcium chloride, got good cement returns above packer collar. Cemented second state with 600 sacks of Tozmix A with 5% alt, good cement returns to surface. Plug down at 5:00 pm. Rig released at 6:00 pm, 8/2/80.

DRILL OUT DV PACKER COLLAR, DRILL OUT CEMENT IN BOTTOM JOINT OF CASING AND DEEPEN HOLE VALLEY VISTA VIEW, INC. #1

8-27-80: Move in Otis spudder.

8-29-80: Rig up. Spool and splice sand line. Swab 4 1/2" casing.

9-2-80: Swabbed 4 1/2" casing to top of cement above DV packer collar. Ran bailer-pick up at 2890', 37' of cement above DV tool. Drilled cement.

9-3-80: Drilled cement and drilled out DV packer collar. Tools ran free through DV tool. Ran bailer-pick up at 3780', 33' of cement above float collar. Checked out casing swab through DV tool - O.K. Swabbed 4 1/2" casing at top of cement. Drilled about 30' of cement.

9-4-80: Drilled cement and drilled out float collar. Drilled cement below float collar in bottom joint of casing. Drilled to 3840'.

9-5-80: Drilled cement, guide show, and a little blacke shale. Drilled: 3845'-53' cement and black shale, little chert. 3853'-57' black shale, some cement, little muddy gray limestone and chert. Changed drill string assembly to drill formation. Well making a very slight show of gas.

9-8-80: Little pressure on well — would not raise gage off peg at 40 psig. Drilled 3' — very hard. 50% limestone and 50% black shale.

9-9-80: Very little pressure on well. Made 1 run, drilled 1', recovered limestone. Drilled 1 1/2 hours on 2nd run where wire line parted on top of tools. S.D. to get fishing tools.

9-10-80: Fished tools out, bailed hole, recovered black shale. Made 1'. TD now 3862'. Took pressure on anulus between 4 1/2" and 8 1/2" — 60 psig with casing head leaking. Blew anulus, repaired casing head, replaced and shut-in. Drilling deeper. Drilled 10 1/2', recorded very black shale with abundant pyrite. Ran measuring machine, got pick-up at 3873'. Shut-in at 6:30 pm.

9-11-80: Casing pressure 10 psig in 13 hrs. Anulus pressure 78 psig in 24 hrs. Drilled 9' of very black shale with abundant pyrite, TD 3882'.

9-12-80: Casing pressure 10 psig in 12 1/2 hrs. Anulus pressure 88 psig in 48 hrs. Drilled 9' of very black shale with abundant pyrite, TD 3891'. S.I. at 6:30 pm.

9-15-80: 9:00 am casing — 26 psig — 62 1/2 hrs. Anulus — 90 psig — 120 hrs. (5 days). Drilled 1 3/4 hrs. when wire line parted. S.D. to get fishing tools S.I. at 11:30 am.

9-16-80: 8:00 am casing — 10 psig — 20 1/2 hrs. Anulus — 90 psig — 6 days. Fished tools out of hole, ran bailer, recovered Black Shale, made 4'. Drilled 4' of very black shale as above, recovered abundant "Brown Break" material in last run. T.D. 3899'. S.I. at 5:00 pm.

9-17-80: 7:39 am casing — 5 psig — 14 1/2 hrs. Anulus — 90 psig — 7 days. String-in drilling line — found T.D. at 3901'. Drilled 5' of limestone. T.D. 3906' (corrected). Tested gas — no gas in 1/4" orifice plate. S.I. at 5:00 pm.

9-18-80: Made on run — drilled 1', recovered limestone. Ran Birdwell — Gamma Ray. Log Tops: Clean limestone 3835-54'; Casing 3845'; Onondaga 3904'; T.D. 3910'. Ran junk basket to check hole — went to T.D. Released rig.

COMPILATION OF MONTHLY REPORTS
RATHBONE PROSPECT
VALLEY VISTA VIEW, INC. #1 WELL
(OCT. 1980 - JAN. 1981)

October 31, 1980

The Valley Vista View Well has been stimulated in the Marcellus. After clean-up the well had a sustained open flow of about 200 mcf/d; when shut in, the pressure mounted quickly to 2200 psi. Tests are continuing.

November 30, 1980

The Valley Vista View, Inc. #1 Well was tested during November — Modified Isochronal Test and Buildup Test. The results will be available in the next month's report. Presently the Gamma Ray, Spinner and Temperature logs are being run prior to setting the bridge plug to allow fracing of the Rhinestreet section. The Rhinestreet frac is scheduled for December 5, 1980.

December 31, 1980

The Valley Vista View, Inc. #1 Well was logged (gamma ray, temperature and spinner) on 12/2/80 through the Marcellus section. A plug was set just below the Rhinestreet section (1300). The Rhinestreet section was perforated and broken down on 12/3/80. No gas production was detected after breakdown.

The well was stimulated on 12/5/80 and was flowed back and cleaned up over the balance of the month. The well was making salty water as of 12/31/80.

Modified Isochronal Test results from the Marcellus section will be forwaroed with the January, 1981 report.

January 31, 1981

The Valley Vista View, Inc. #1 Well (Rhinestreet Section); clean up operations continued (swabbing salt water) through January 12, 1981. The well, at that time, was making 1.5 barrels of salt water per hour. The highest recorded gas production rate was 2 MCF/D. Pressure build-up performance was poor at 76 psig in 69 hours. In light of the above, the well was shut-in and the rig was released on January 13, 1981. On January 15, 1981 Birdwell ran the Gamma Ray/Tracer Log through the Rhinestreet Section.

Presently, arrangements are being made to squeeze cement into the Rhinestreet perforations to shut off the salt water production. Subsequently, the calseal and bridge plug will be drilled out to re-open the Marcellus section. We hope to commence the squeeze and drilling operations in February, 1981.

Modified Isochronal Test results from the Marcellus section require additional interpretation and therefore will be available in next month's report.

RHINESTREET STIMULATION AND CLEAN-UP RATHBONE PROSPECT VALLEY VISTA VIEW, INC. #1 WELL

The Rhinestreet shale zone was isolated with a Baker plug which was set a 1300 feet. The zone was perforated from 940 feet to 1225 feet, broken down and balled off.

Two days later, the Rhinestreet zone was stimulated and opened to flow back. After more than a month of swabbing, the well continued to produce a negligible amount of gas and 1.5 barrels of water per hour. On 1/13/81 the well was shut-in.

A cement squeeze of the perforations into the Rhinestreet zone commenced on 2/25/81. As of 3/3/81 following a second cement squeeze, the Rhinestreet zone was successfully squeezed off and the plug at 1300 feet was to be drilled out on 3/4/81; therefore, re-opening the Marcellus zone to the surface with the Rhinestreet behind cement.

COMPLETION REPORT
RATHBONE PROSPECT
VALLEY VISTA VIEW, INC. #1 WELL
(OCT. 29, 1980-MAR. 4, 1981)

10-29-80: Casing pressure 695 psig in 15 hours. Found fluid level at 1800'. Swabbed down to 3800. Making 40-50' of fluid per hour with a little gas.

10-30-80: Casing pressure 1230 psig in 15 1/2 hours. Found fluid level at 3500', Swabbed down to 3800', making 40' plus or minus of fluid per hour with some gas. Open flow test 200 MCF after open for 9 hours.

10-31-80: Casing pressure estimated 2200 psig in 15 1/2 hours. (Estimated maximum pressure on 2000 psi gauge). Annulus pressure 80 psig. Blew well down 2 1/2 minutes to steady flow. No fluid or moisture. Rigged up lubricator and swabbed to 3760'. Recovered estimated 30' of fluid. Continuing to swab. Swabbed 3800'. Making estimated 4250' of gas and fluid per hour. Open flow test 300 MCF per day, open 7 hours.

11-3-80: Casing pressure 2300 psig in 63 hours. Ran swab to 3800', recovered very little fluid. Shut down for 5 hours with well open. Ran swab and recovered very little fluid. Open flow test 180 MCF per day. Open 8 1/2 hours.

11-4-80: Dead weight test 2098 psig in 22 1/2 hours.

11-5-80: Well shut-in.

11-6-80: Dead weight test 2141 psig in 67 hours.

11-7-80: Dead weight test 2147 psig in 93 1/2 hours.

11-12-80: Dead weight test 2152 psig in 215 hours.

11-13-80: Dead weight test 2156 psig in 232 hours. Ran Modified Isochronal Flow Test. Final flowing pressure through 1/2" choke, 25 psig, increased to 125 psig in 1/2 hour on 1/16" plate. Left well flowing for stabilization test.

11-14-80: Running stabilization test. Dead weight test 531 psig at noon.

11-15-80: Final stabilization pressure 545 psig through 1/16" plate. Shut in for pressure build up test.

11-18-80: Casing pressure 1890 psig.

Recording chart showed build up to 1790 psig from noon on November 15 to the evening of Novemeber 16. At this time a sudden increase in pressure occurred to 2000 psig (maximum on recording chart). Pressure remained at maximum until noon on November 18 when pressure decreased to 1890 psig. These events indicated a possible mechanical problem with the pressure recorder and probably an influx of fluid into the wellbore.

11-21-80: Dead weight test 1921 psig. Removed chart and pressure recorder from wellhead. Chart indicated pressure had been fluctuating from 1850 to 2000 (maximum).

12-2-80: Casing pressure 2000^{+} psig in 17 days. Blew well, no fluid. Ran swab found 200' of fluid in hole. Swabbed and blew well dry. Ran Birdwell logs, gamma ray, temperature and spinner. Found TD at 3878. Logs indicated gas coming from top of perforated section at 3820. Ran correlation log in Rhinestreet shale.

12-3-80: Set Baker plug at 1300' with calseal plug on top. Spotted 500 gals, 15% CL acid and 350 gals of 2% KCL water. Found top of calseal plug at 1280'. Perforated 19 holes from 940-1225'. Broke down formation dropped perf balls. First break down 2100 psi, treated 12 bbls per minute at 2000 psi. Dropped perf balls, pumped 10 bbls per minute at 3100 psi. Instantaneous shut-in pressure 950 psi. Open well at 9:15 pm. Small flow back.

12-4-80: Found top of fluid at 300'. Swabbed well. Making estimated 100' per hour.

12-5-80: Casing pressure 40 psig in 15 hours. Ran swab. Found 450' of fluid. Swabbed well dry. Ran Halliburton frac 630,000 SCF nitrogen, average pressure 1721 psi, average injection rate 6.3 bbls per minute. Used 290 bbls of water, 800 sacks of sand. Completed frac at 12:50 pm. Open well through 1/8" choke. Flowed 1 1/4 hrs. Installed 1/4" choke Flowed 5 minutes. Making frac sand. Installed 1/8" choke and flowed well.

12-6-80: Well flowing fluid and foam. 8:15 am installed 1/2" choke. Flowed 1 hour. Blowing fluid and nitrogen with a little frac sand. 9:30 am installed 3/4" choke, flowed 1/2 hour, fluid and nitrogen. 10:15 am flowed through 2" for 3 hours. Swabbed foam and water.

12-8-80: Casing pressure 540 psig in 40 hours. Blew well 2 hours through 2". Blew fluid and foam. Swabbed well to 925'. Tagged bottom found 100' of fill up.

12-9-80: Casing pressure 375 psig in 15 hours. Well back down 30 minutes no fluid. Swabbed fluid, top of fill up. Ran sand pump. Recovered frac sand with abundant shale. Took out 8' of frac sand. Swabbed 500' of fluid. Mostly foam.

12-10-80: Casing pressure 280 psig in 14 hours. Blew well down. No fluid. Ran swab. Recovered 700' of fluid. Ran sand pump, 10' of fill up overnight. Making estimated 50' of fluid per hour. Cleaned out 50' of sand and swabbed dry.

12-11-80: Casing pressure 260 psig in 15 hours. Swabbed 400' of fluid. Ran sand pump. Found 8-10' of fill up overnight. Cleaned out 25-30' of sand. Recovered 30 perf balls and a little calseal. Cleaned out to top of plug. Swabbed dry.

12-12-80: Casing pressure 220 psig in 15 hours. Swabbed to top of plug. No sand in well. Making estimated 150' of fluid per hour.

12-15-80: Casing pressure 250 psig in 62 hours. Found 800' of fluid in hole. Swabbed down. Fluid is very foamy. Ran sand pump. Took out 8' of sand. Making 100-150' of fluid per hour.

12-16-80: Casing pressure 130 psig in 15 hours. Found 700' of fluid in hole. Swabbed down fluid. Is somewhat foamy. No sand in hole. Well making a little less fluid than before.

12-17-80: Casing pressure 140 psig in 15 hours. Found 350' of fluid, swabbed dry.

12-18-80: Casing pressure 100 psig in 15 hours. Found 400' of fluid. Swabbed to plug back TD. Making 300' per hour.

12-19-80: Casing pressure 100 psig in 15 hours. Found 400' of fluid. Making 300' per hour.

12-22-80: Casing pressure 200 psig in 65 hours. Found 400' of fluid. Swabbed down. Making 150' per hour. Estimated 5' of fluid fill up.

12-23-80: Casing pressure 75 psig in 15 hours, Found 400' of fluid. Swabbed down. Fluid is still foamy. Ran sand pump. Recovered 8' of frac sand with abundant shale.

12-24-80: Casing pressure 125 psig in 15 hours. Found 400' of fluid. Swabbed down. Making 150' per hour.

12-25-80: Well shut down.

12-26-80: Casing pressure 155 psig in 40 nours. Found 500' of fluid. Swabbed down. Making 150' per hour.

12-29-80: Casing pressure 110 psig in 64 hours. Found 450' of fluid. Swabbed down. Making 150' per hour.

12-31-80: Casing pressure 60 psig in 40 hours. Found 450' of fluid. Well swabbed down. Fluid is moderately salty. Making 150' per hour.

1-2-81 : Casing pressure 75 psig in 40 hours. Found 450' of fluid. Swabbed down. Making 150' per hour.

1-5-81 : Casing pressure 120 psig in 64 hours. Found 450' of fluid in hole. Swabbed down. Making 150' per hour.

1-6-81 : Casing pressure 75 psig in 16 hours. Found 425' of fluid in hole. Swabbed down. Making 100' per hour. Open flow test 2730 cu. ft. per day. Open 8 1/2 hours.

1-7-81 : Casing pressure 100 psig in 15 hours. Found 375' of fluid. Swabbed down.

1-8-81 : Casing pressure 120 psig in 15 hours. Found 300' of fluid in hole. Swabbed down. Making 100' per hour.

1-9-81 : Casing pressure 105 psig in 15 hours. Found 300' of fluid in hole. Swabbed down. Making 100' per hour.

1-12-81 : Casing pressure 180 psig in 65 hours. Found 400' of fluid in hole. Swabbed down. Making 100' per hour.

1-13-81 : Shut down. Released rig.

1-14-81 : Shut down.

1-15-80 : Casing pressure 76 psig, dead weight test 69 hours. Blew well down to log. Birdwell ran tracer log. Shut-in at 2:30 pm. Good results from tracer survey showing which perforations took frac fluid.

2-23-81: Casing pressure 265 psig in 39 days. Took gas sample for analysis. Tally Well Service Inc. bringing in service rig and moved in water tank. Drill pipe and dozer on location.

2-24-81: Blew well. Blew down in 30 seconds. Not enough gas to test. Found fluid level at 700'. Recovered sample for analysis. Tagged bottom with sand line 1280'. Added fresh water to hole. Could only bring fluid level up to 400'. Added another 30 bbls of water and shut down.

2-25-81: Found fluid level at 450'. Ran drill pipe, tagged bottom at 1286', pulled one joint and hung drill pipe at 1255' to spot cement. Pumped 35 sacks of Thixatropic cement, got circulation. Went back down hole. After job completed pulled drill pipe and shut down to wait on cement.

2-26-81: Went in hole with sand line, found fluid level at 250' and top of cement at 975'. Pumped water to test. Took 6 bbls per minute at 1300 psi. Ran drill pipe with RTTS packer, set at 804'. Pumped 100 sacks of Common cement at 700 psi and displaced cement with "hesitation" squeeze. Displaced cement to calculated depth 900'. Shut down to wait on cement.

2-27-81: Pulled drill pipe and packer. Found bottom 3 joints full of cement. Pump tested casing for 10 minutes at 2000 psi. Casing held pressure. Rigged up circulating bit and ran drill pipe in hole. Drilled cement from 804' to 930'.

2-28-81: Drilled cement from 930' to 996'. Pump tested casing against BOP to 2000 psi. Did not take fluid. Drilled cement to 1056'.

3-1-81: Drilled cement from 1056' to 1232'. Halliburton standing by to test casing. Started to pull drill pipe off bottom at 6:00 pm when pipe pulled tight at 10' off bottom. Well circulated but drill pipe did not rotate. Worked pipe for one hour. Did not come free.

3-2-81: Rigged Halliburton to circulate and worked drill pipe. Pipe came free at 11:00 am. Started drill pipe out of hole. Pumped out circulating bit and mixed 2% KCL water. Completed trip out of hole. Found bit locked up by small piece of steel. Pump test casing to 2000 psi. Casing leaded off to 1000 psi in 15 minutes. Repeated test several times with the same results. Pumped about 1/10 bbls to repressure to 2000 psi. Rigged up to sand pump.

3-3-81: Drilled ice out of top of 4 1/2" casing. Ran sand pump. Recovered pieces of screwdriver. Cleaned hole until all of screwdriver was apparently recovered. Rigged up to drill remaining cement and Baker plug.

3-4-81: Drilled cement to top of Baker plug. Rigged up blow out preventers and tied down flow lines. Annulus pressure 90 psig. Tested the blow out preventer. Started drilling at 10:45 am when Universal joint broke on power take off. Shut down for repairs.

GAS WELL DELIVERABILITY TEST SUMMARY

APPENDIX II 2.6

GENERAL DATA

WELL NAME No. 1 Valley Vista View

LOCATION Steuben Co., NY W

FIELD OR AREA Rathbone Prospect

ELEVATION (CF) ____ (KB) 1465 ft

POOL OR ZONE Marcellus Shale

RESERVOIR TEMPERATURE 125 °F

PERF./OPEN HOLE INTERVAL Perf. 3820'-3835'(45 holes); Open hole: 3841'-3910' ft (KB)

CASING ID 4.052 in TUBING ID ____ in OD 4.50 in PACKER ____ ft (KB)

RESERVOIR GAS PROPERTIES: G .60E P_c ____ T_c ____ MOL %: N_2 ____ CO_2 ____ H_2S ____

LICENSEE ____ OPERATOR (Co) Donohue Anstey & Morrill

TYPE OF TEST Modified Ischronal

FINAL DATE OF TEST Nov. 21 19 80

PRODUCTION DATA

RATE NO.	DURATION hours	GAS PRODUCTION Mscfd	CONDENSATE PRODUCTION bbl/d	COND./GAS RATIO bbl/Mscf	GAS-EQUIVALENT OF CONDENSATE Mscfd	TOTAL PRODUCTION-RATE Mscfd	WATER PRODUCTION bbl/d	WATER/GAS RATIO bbl/MMscf
1	1	319	0			319	0	
2	1	411	0			411	0	
3	1	376	0			376	0	
4	1	226	0			226	0	
EXTENDED RATE	44.5	104	Odor			104	Trace	

GAS PRODUCED THROUGH: Casing ~~TUBING~~ [X] ANNULUS [ ] TO: PIPE LINE [ ] VENT [X] FLARE [ ]

FLARE STACK HEIGHT ____ ft DIAMETER ____ in

TOTAL VOLUME OF GAS PRODUCED DURING CLEANUP AND TEST ____ Mscf

EQUIPMENT LIST

- LINE HEATER [ ]
- L.P. SEPARATOR [ ]
- H.P. SEPARATOR [ ]
- CRITICAL FLOW PROVER [X]
- ORIFICE METER [ ]
- LIQUID STORAGE TANK [ ]
- ____ [ ]
- ____ [ ]
- ____ [ ]

REMARKS

STABILIZED SHUT-IN RESERVOIR PRESSURE ($\bar{p}_R$) 2354 psia

ABSOLUTE OPEN FLOW POTENTIAL 110 Mscfd

WELLHEAD OPEN FLOW POTENTIAL N/A Mscfd

GAS WELL DELIVERABILITY TEST – FIELD NOTES

WELL NAME No. 1 Valley Vista View

LOCATION Steuben Co., NY W

FIELD OR AREA Rathbone Prospect

POOL OR ZONE Marcellus Shale

PERF./~~OPEN HOLE INTERVAL~~ 3820'-3835' (45 holes)
Open Hole: 3841'-3910'

PRODUCING THROUGH: ~~TUBING~~ ~~ANNULUS~~ 4 1/2" casing

WELL BLOWN FOR N.A. minutes

SPRAY: WATER/CONDENSATE CLEAR IN ______ minutes

DATE SHUT-IN Nov. 3 19 80

TIME 4:40 PM

TOTAL SHUT-IN TIME 232 hours

SHUT-IN NO. 1 (INITIAL)

DATE	TIME	CUMULATIVE SHUT-IN TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F
11-4-80	3:00P	22 1/2		2098	-
11-6-80	11:30A	67		2141	-
11-7-80	2:00P	93 1/2		2147	-
11-12-80	4:00P	215 1/2		2152	-
11-13-80	8:25A	232		2156	-

REMARKS

All pressures are DWT unless otherwise indicated.

Test run with critical flow prover immediately down stream from wellhead.

Early portion of Flow No. 1 does not appear on chart due to pressure limits. On chart at 8:45 AM.

FLOW NO. 1

WELL OPENED AT 8:25 AM / ~~PM~~ Nov. 13 19 80

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F	METER OR PROVER DATA STATIC PRESSURE psig	DIFFERENTIAL inches H_2O	TEMPERATURE °F
11-13-80	8:25A	-		2156	-	2156		-
	8:40	0.25		2012	-	2012		-
	8:55	0.50		1894	-	1894		-
	9:10	0.75		1789	-	1789		-
	9:25	1.00		1695	-	1695		-

METER RUN OR PROVER SIZE 2 inches

ORIFICE SIZE 3/32 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ____ °F

LP SEP. ____ psig, ____ °F

CONDENSATE PRODUCTION RATE None Bbl per hour

TOTAL ____ Bbl

WATER PRODUCTION RATE Little condensation ~~on back of plate fresh~~ Bbl per hour

TOTAL ____ Bbl

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 1695 psig

WELL SHUT-IN AT 9:25 AM/~~PM~~ Nov. 13 19 80

TOTAL FLOW TIME 1 hours

NOTE: FLOWING WELLHEAD PRESSURES AND TEMPERATURES MUST BE OBTAINED UPSTREAM OF ANY CHOKING DEVICE

GAS WELL DELIVERABILITY TEST - FIELD NOTES

SHUT-IN NO. 3 (INTERMEDIATE)

DATE	TIME	CUMULATIVE SHUT-IN TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F
11-13-80	11:25A	-		1161	-
	11:40	0.25		1206	-
	11:55	0.50		1242	-
	12:10P	0.75		1276	-
	12:25	1.00		1308	-

REMARKS

FLOW NO. 3 WELL OPENED AT 12:25 ~~AM~~/PM 11-13 19 80

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F	METER OR PROVER DATA STATIC PRESSURE psig	DIFFERENTIAL inches H_2O	TEMPERATURE °F
11-13-80	12:25P	-		1308	-	1308		-
	12:40	0.25		820	-	820		-
	12:55	0.50		530	-	530		-
	1:10	0.75		350	-	350		-
	1:25	1.00		247	-	247		-

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 1/4 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ___ °F IP SEP. ___ psig, ___ °F

CONDENSATE PRODUCTION RATE None Bbl per hour TOTAL ___ Bbl

WATER PRODUCTION RATE ___ Bbl per hour TOTAL ___ Bbl

Little condensation on back of plate-fresh.

FINAL FLOWING WELLHEAD PRESSURE: TUBING ___ CASING 247 psig

WELL SHUT-IN AT 1:25 ~~AM~~/PM 11-13 19 80 TOTAL FLOW TIME 1 hours

GAS WELL DELIVERABILITY TEST - FIELD NOTES

SHUT-IN NO. 4 (INTERMEDIATE)

DATE	TIME	CUMULATIVE SHUT-IN TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F
11-13-80	1:25P	-		247	-
	1:40	0.25		310	-
	1:55	0.50		356	-
	2:10	0.75		404	-
	2:25	1.00		452	-

REMARKS

Flow No. 4 2:45P - pressure dropped below 50 psig, minimum on DWT'er, - installed gauge

FLOW NO. 4 WELL OPENED AT 2:25 ~~AM~~ / PM 11-13 19 80

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F	METER OR PROVER DATA STATIC PRESSURE psig	DIFFERENTIAL inches H_2O	TEMPERATURE °F
11-13-80	2:25P	-		452	-	452		-
	2:40	0.25		73	-	73		-
	2:55	0.50		35 (gauge)	-	35 (gauge)		-
	3:10	0.75		25 (gauge)	-	25 (gauge)		-
	3:25	1.00		25 (gauge)	-	25 (gauge)		-

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 1/2 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ____ °F LP SEP ____ psig, ____ °F

CONDENSATE PRODUCTION RATE None Bbl per hour TOTAL ____ Bbl

WATER PRODUCTION RATE None Bbl per hour TOTAL ____ Bbl

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 25 psig

WELL SHUT-IN AT ____ AM/PM ____ 19 ____ TOTAL FLOW TIME 1 hours

GAS WELL DELIVERABILITY TEST - FIELD NOTES

XXXXXXXXXXXX FLOW NO. 5 TO STABILIZATION

Date	Time	Cum. Hrs.		Casing psig		Prover psig		
11-13-80	3:25P	-		25 (gauge)		25 (gauge)		
	3:55	0.50		125 (gauge)		125 (gauge)		
	6:00	2.50		395 (chart)		395 (chart)		
	8:00	4.50		485 (chart)		485 (chart)		
	10:00	6.50		515 (chart)		515 (chart)		
	12:00	8.50		512 (chart)		512 (chart)		
11-14-80	4:00A	12.50		510 (chart)		512 (chart)		
	8:00	16.50		518 (chart)		518 (chart)		
	12:00	20.50		531		531		
	6:00P	26.50		530 (chart)		530 (chart)		
	12:00	32.50		540 (chart)		540 (chart)		
11-15-80	6:00A	38.50		542 (chart)		542 (chart)		
	12:00	44.50		545 (chart)		545 (chart)		
	Note:	11-14-80	@ 12:00 A.M.	- chart pressure was		530 psig		
		when DWT	was 531 psig					

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 3/32 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ____ °F LP SEP. ____ psig, ____ °F

CONDENSATE PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

Found little fluid in prover-strong condensate odor, no salty taste.

WATER PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 545 psig

WELL SHUT-IN AT 1:15 XX/PM Nov. 15 19 80 TOTAL FLOW TIME 45.75 hours

FINAL SHUT-IN WELLHEAD PRESSURE: TUBING ____ CASING 1921 psig

DURATION OF FINAL SHUT-IN 144 hours TESTED BY (CO.) Arlington Exploration Company

GAS WELL DELIVERABILITY TEST CALCULATIONS - FLOW RATES

(BASE CONDITIONS = 14.65 psia and 60 °F)

CRITICAL FLOW PROVER $q = 10^{-3}\ C\ P\ F_{tf}\ F_g\ F_{pv}$

RATE NO.	PROVER SIZE inches	ORIFICE DIAMETER inches	BASIC ORIFICE COEFFICIENT (C) Mscfd/lb.	STATIC PRESSURE (P) psia	FLOW TEMP. FACTOR F_{tf}	SPECIFIC GRAVITY FACTOR F_g	SUPERCOMP. FACTOR F_{pv}	FLOW RATE q ~~MM~~scfd
1	2	3/32	0.1863	1710	1.0000	1.0000	1.0000	319
2	2	1/8	0.3499	1176	"	"	"	411
3	2	1/4	1.4360	262	"	"	"	376
4	2	1/2	5.6530	40	"	"	"	226
5	2	3/32	0.1863	560	"	"	"	104

GAS WELL DELIVERABILITY TEST CALCULATIONS

(BASE CONDITIONS = 14.65 psia and 60 °F)

WELL NAME Valley Vista View, Inc. #1 LOCATION Rathbone Twp. Steuben Co., NY W__

POOL OR ZONE Marcellus Shale FINAL DATE OF TEST 11/21 1980

SIMPLIFIED ANALYSIS

	DURATION hours	SANDFACE PRESSURE psia	CALC.	MEAS.	$p^2 \times 10^{-3}$ psia²	$\Delta p^2 \times 10^{-3}$ psia²	FLOW RATE (Q) ~~MM~~scfd
INITIAL SHUT-IN	232	2364	x		5588		
FLOW 1	1	1862	x		3467	2121	319
SHUT-IN	1	1966	x		3865		
FLOW 2	1	1280	x		1638	2227	411
SHUT-IN	1	1441	x		2076		
FLOW 3	1	285	x		81	1995	376
SHUT-IN	1	508	x		258		
FLOW 4	1	44	x		1.9	256	226
EXTENDED FLOW	44.5	610	x		372	5216	104
FINAL SHUT-IN	144	2108	x		4444		

RESULTS

$q = C\left(\bar{p}_R^2 - p_{wf}^2\right)^n$

slope n = 0.67*

$\bar{p}_R$ = 2364 psia

$C = \dfrac{q}{\left(\bar{p}_R^2 - p_{wf}^2\right)^n}$

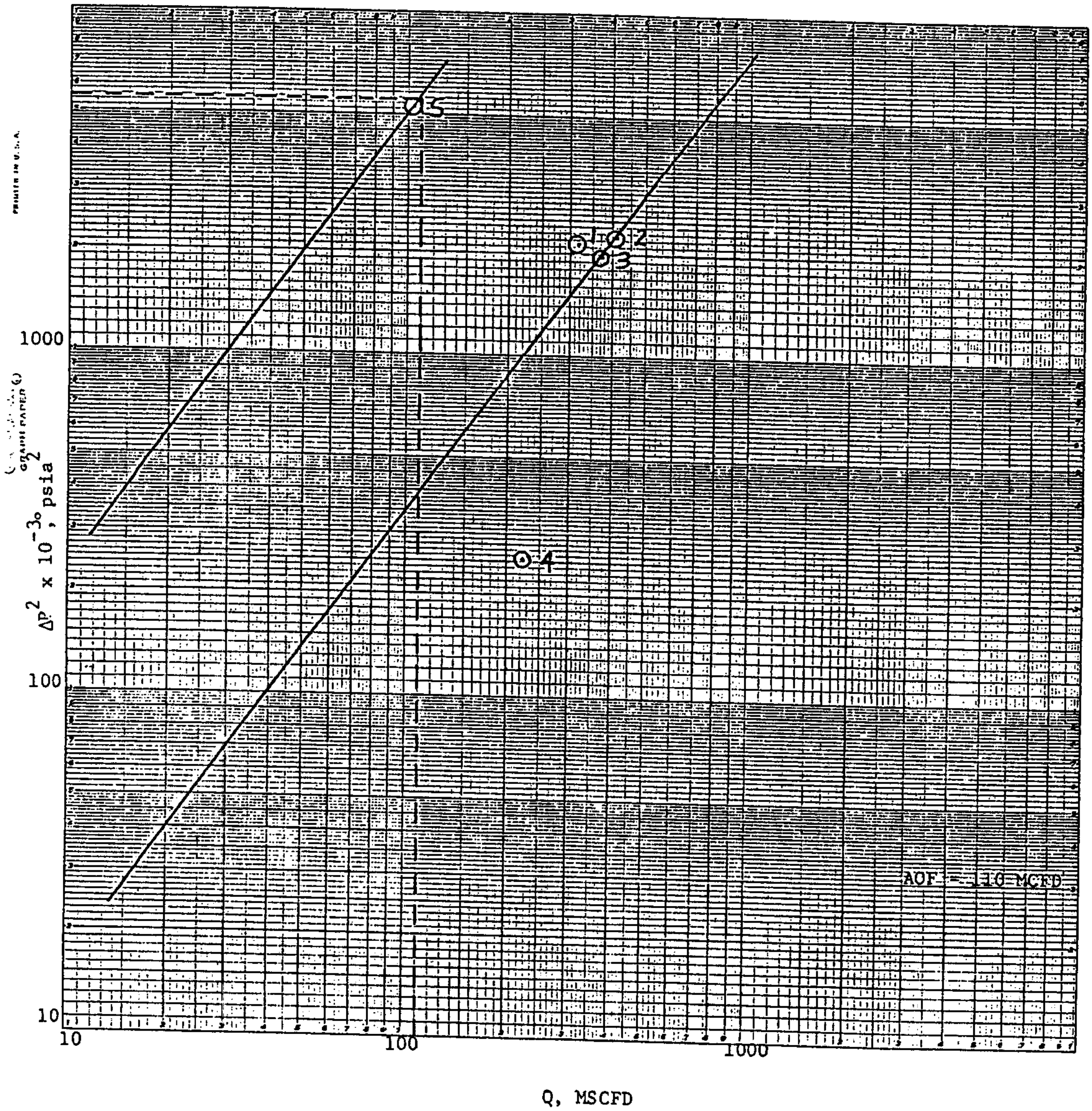
= 0.34 MCFD/psi^2

AOF (~~M~~Mscfd)

= 110 MSCFD

*This slope calculation utilizes points generated by flow 1, flow 2 and flow 3. Flow 4 is not used because of the inordinately low final flowing pressure.

MODIFIED ISOCHRONAL TEST
VALLEY VISTA VIEW, INC. NO. 1 WELL
MARCELLUS SHALE
NOVEMBER 21, 1980



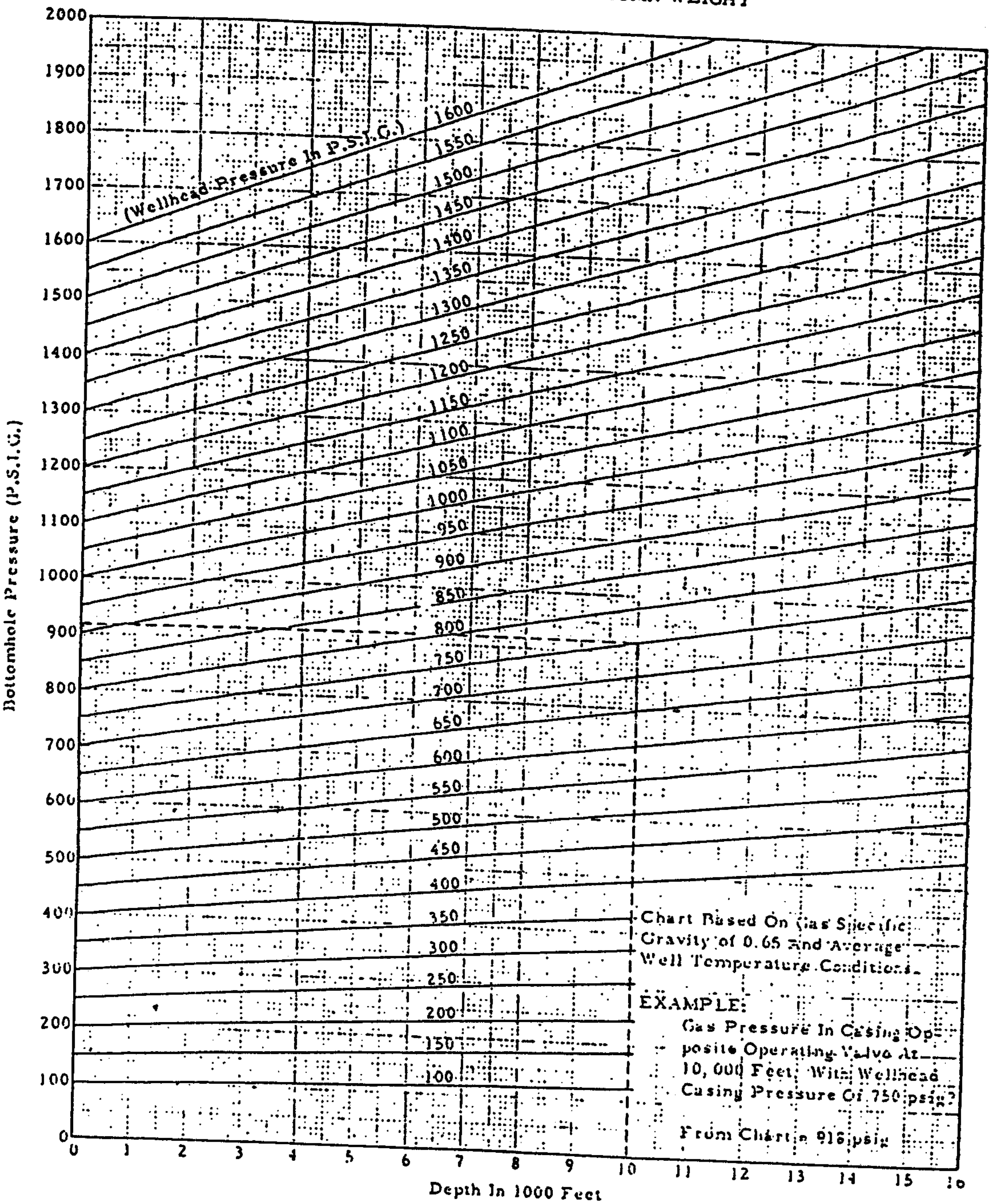
Size of Orifice (inches)	2-Inch Pipe C	Size of Orifice (inches)	4-Inch Pipe C
1/16	0.0846	1/4	1.384
3/32	0.1863	3/8	3.110
1/8	0.3499	1/2	5.564
3/16	0.8035	5/8	8.668
7/32	1.1090	3/4	12.422
1/4	1.4360	7/8	15.893
5/16	2.2080	1	22.007
3/8	3.1420	1 1/8	27.721
7/16	4.5030	1 1/4	34.229
1/2	5.6530	1 3/8	41.210
5/8	8.5500	1 1/2	49.106
3/4	12.4900	1 3/4	67.082
7/8	17.1800	2	88.628
1	22.5800	2 1/4	113.617
1 1/8	28.9200	2 1/2	142.490
1 1/4	36.5100	2 3/4	176.420
1 3/8	44.8600	3	216.790
1 1/2	55.6400		

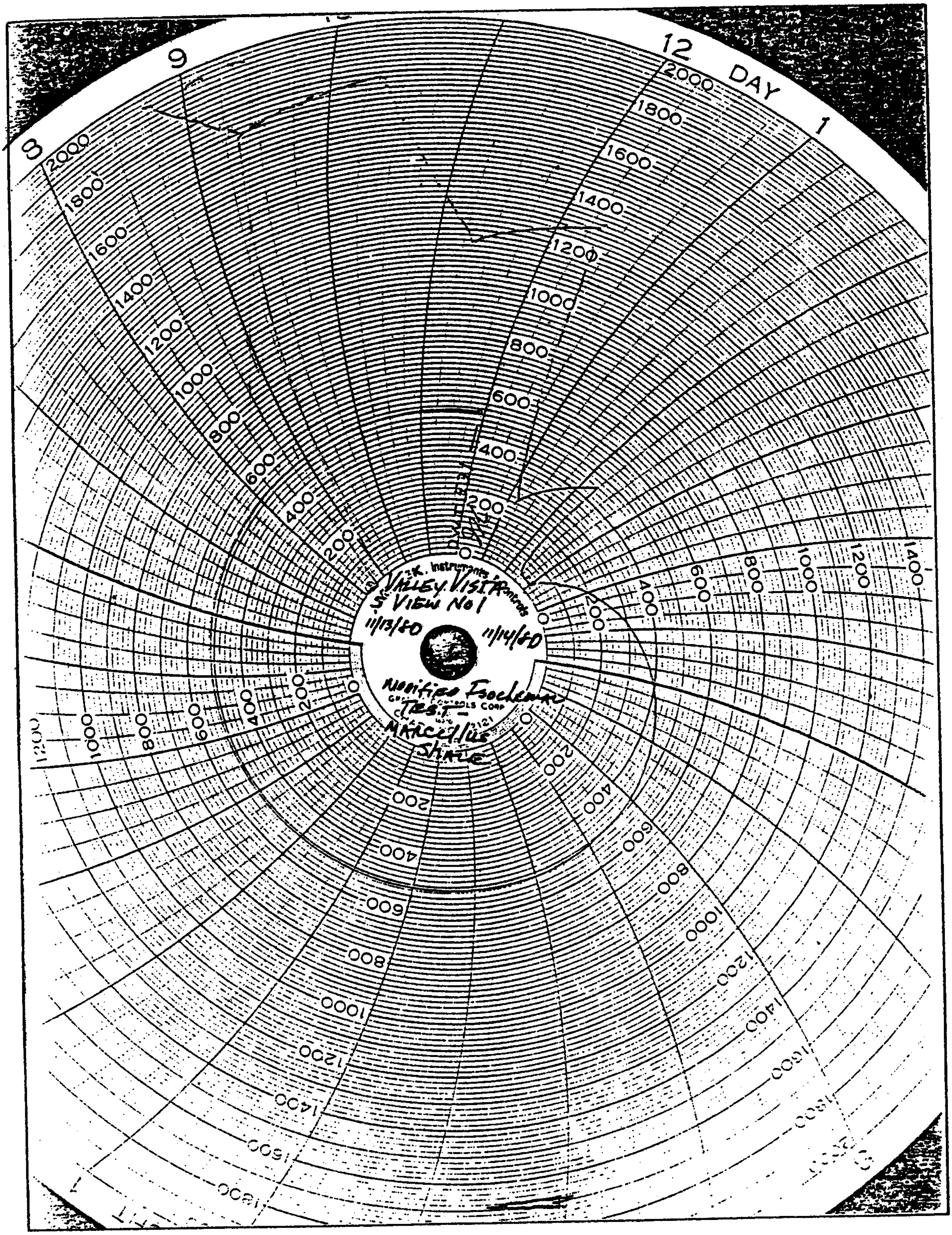
TABLE 6-1 ORIFICE COEFFICIENTS FOR 2" AND 4" FLOW PROVERS

From Railroad Commission of Texas (1950)

CHART NO. V

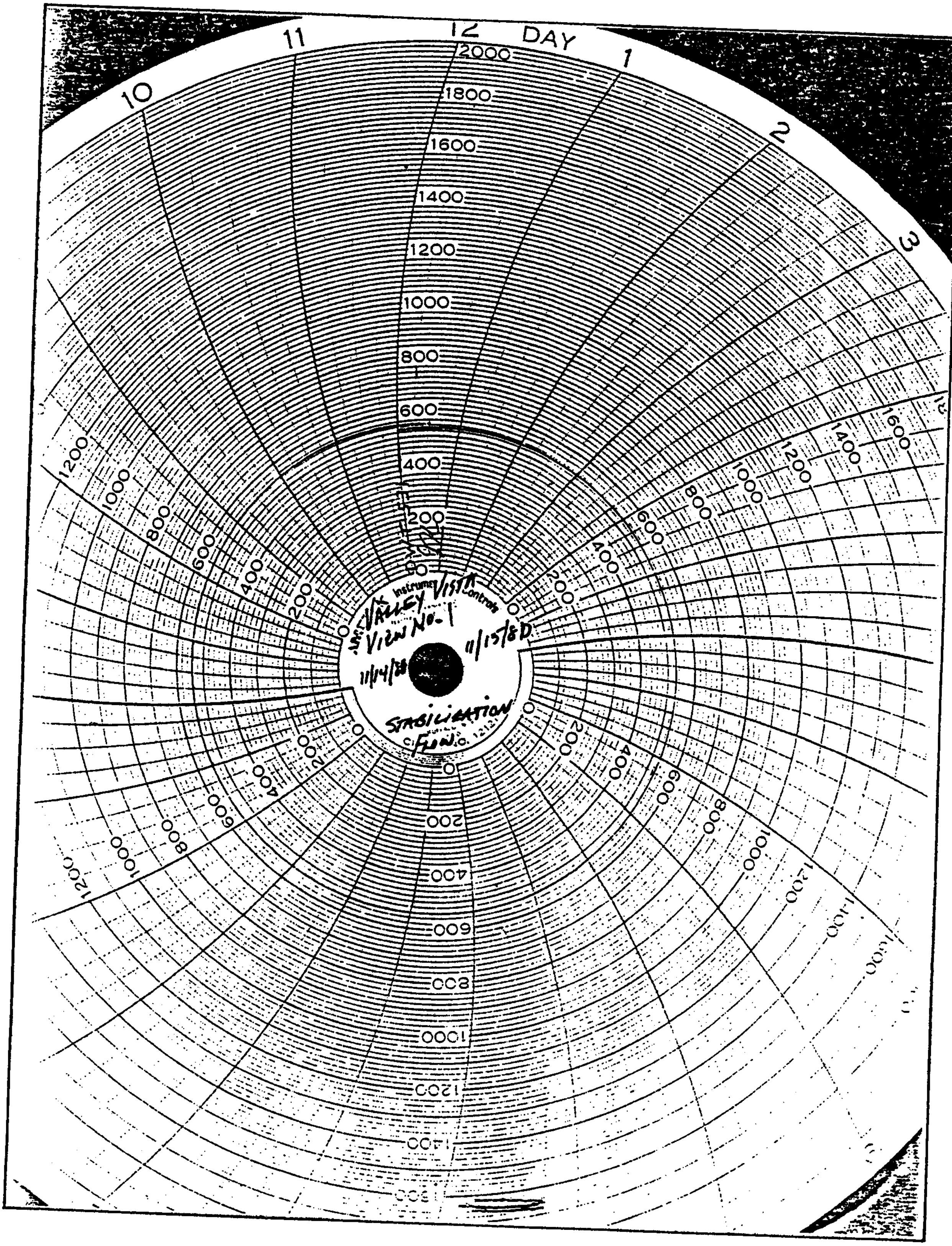
PRESSURE DUE TO GAS COLUMN WEIGHT





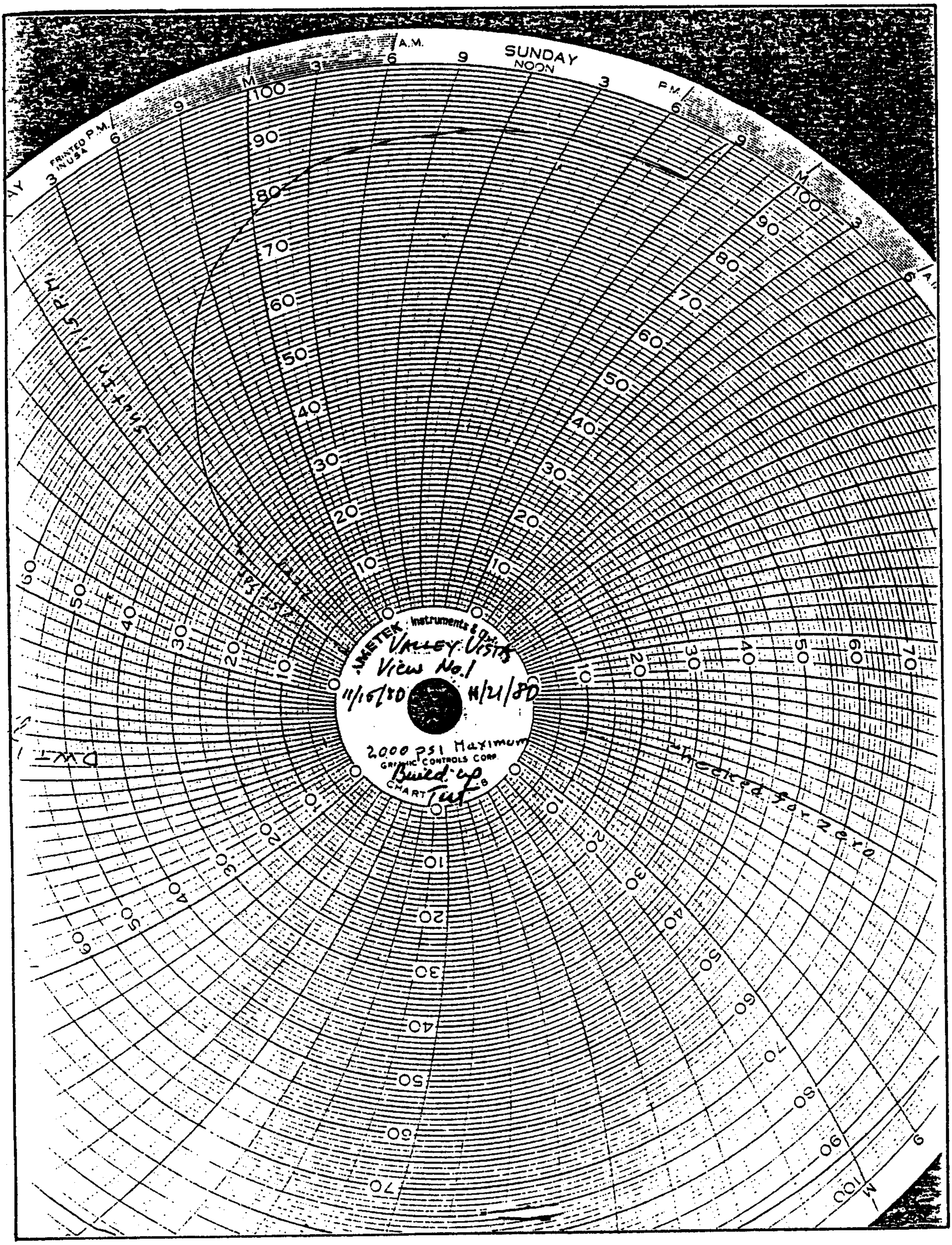
Modified Isochronal Test - Marcellus Shale - Valley Vista View No. 1 Performed 11/13/80-11/14/80

Pressure Recording Chart



Stabilization Flow - Valley Vista View No. 1
Performed 11/14/80-11/15/80

Pressure Recording Chart



Build-up Test - Valley Vista View No. 1 Performed
11/15/80-11/21/80

EXPLORATION RATIONALE
DANSVILLE PROSPECT
METER, KENNEDY, HOWE UNIT #1 WELL

1. As at Rathbone, it has not proved possible to reconstruct with certainty the locations and history of the wells in this old field. Map 12 shows the given locations for the wells for which well-card records are preserved; Map 13 adds the additional well locations preserved on the tax map. We have no idea what constituted the boundary between a dry hole and a producer in 1923; in any case, it is known that the promotion was a financial failure.

2. There is no geological significance to the alignment of the wells. It was soon discovered that drilling in the broad river valley was made problematical by unconsolidated fill, so the wells were generally placed a short distance up the hillside.

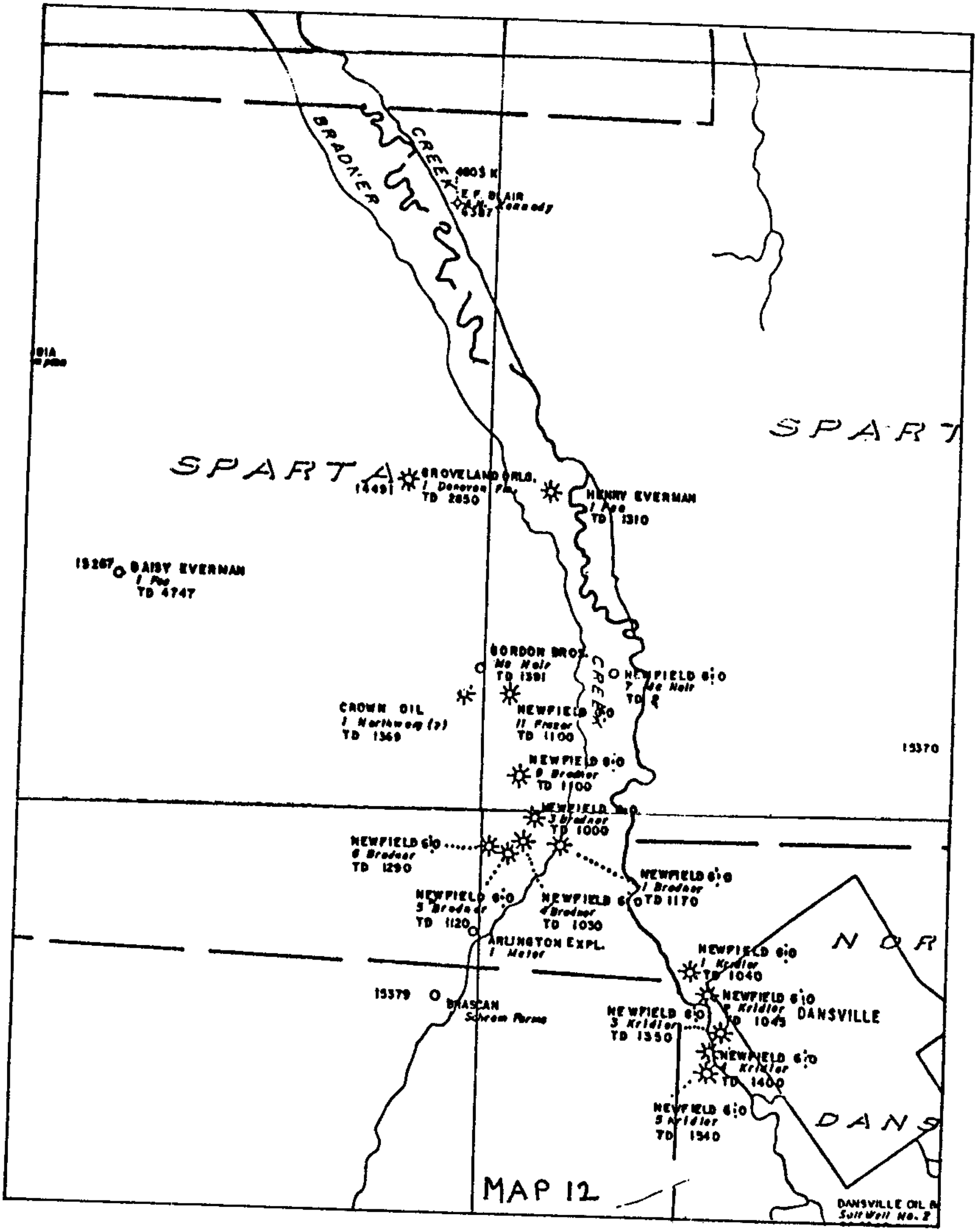
3. Map 14 shows points of control for the depth to the Onondaga. We take these to suggest a gentle regional dip to the south-south-east. Map 15 shows the total depth of the wells for which we have data; from this it is evident that only the arrowed wells reached and penetrated the important lower levels of the Marcellus shale. Perhaps if the old-timers had drilled on...?

4. Map 16 shows the depths at which gas was obtained, for the wells for which we have data. It is clear that, in general, the gas-producing zones are not stratigraphically equivalent.

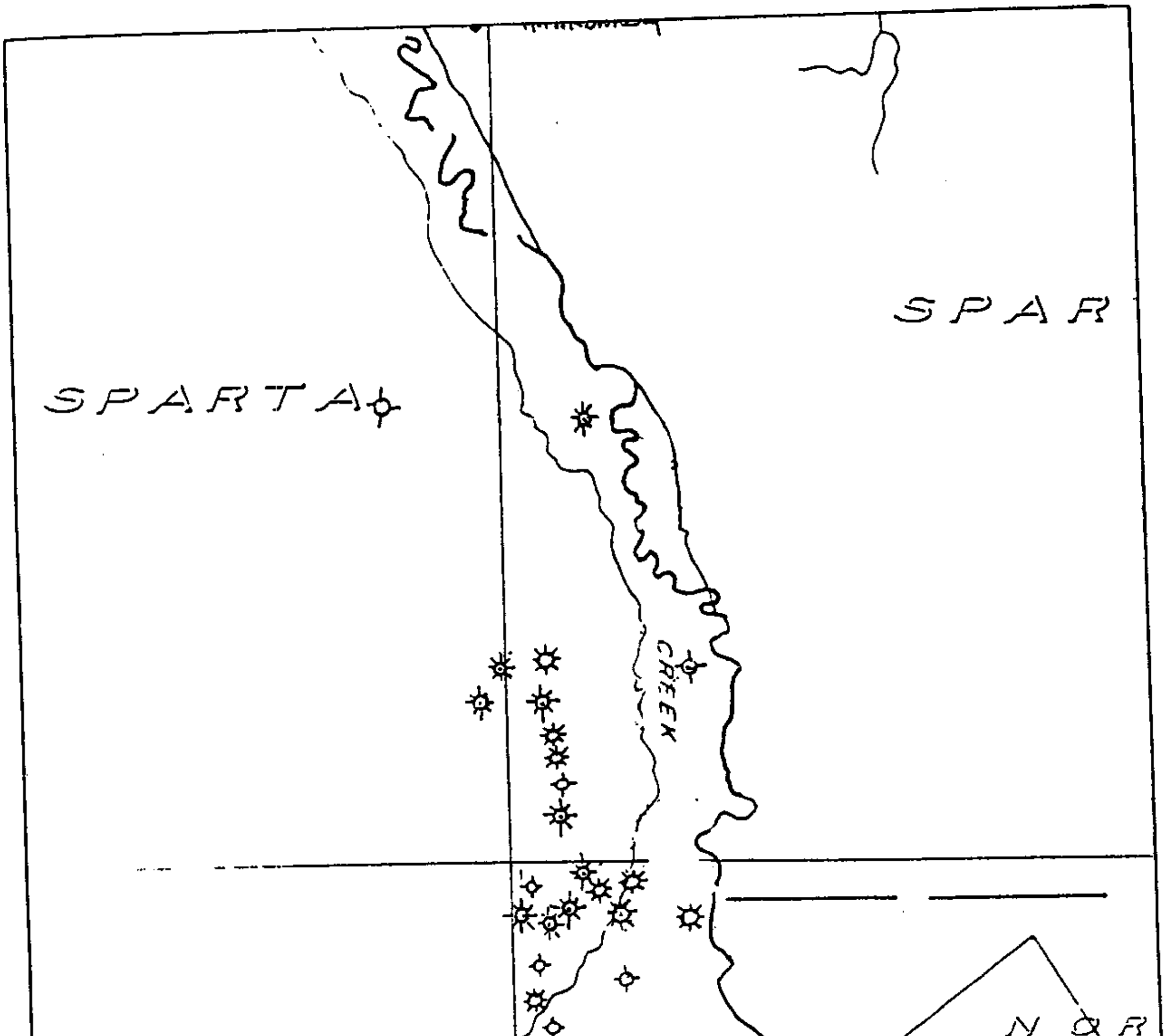
5. Bringing together all this information, we conclude that no geological criteria can be given for choice of the new well location. All we can say is that our major hope lies in the benefit of modern stimulation techniques.

6. Much of the area of the old field is no longer available for lease, having been used for the Genesee Expressway. Of that which remains, most is under lease to Columbia. Although we are still hoping to receive a farmout from

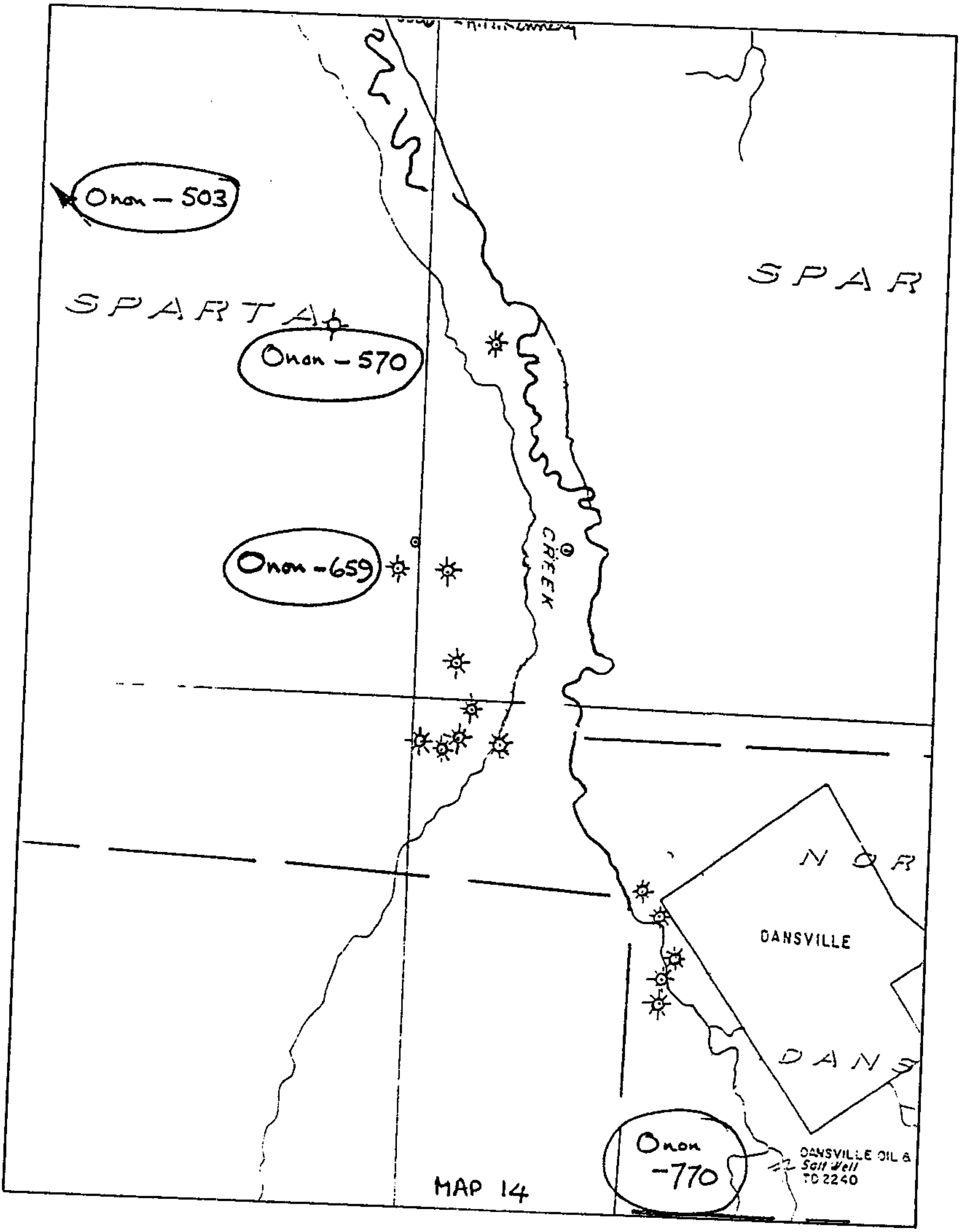
Columbia, it became evident that uncertain delays were inevitable. Of the few possible sites remaining, the first proved unnegotiable, and our final location (shown on Map 17) is our next choice. As noted earlier, we have no reason to suppose that this is either better or worse than any other. Other things being equal, we would probably have moved it a little further north, but considerations of access make us content with the location as shown.



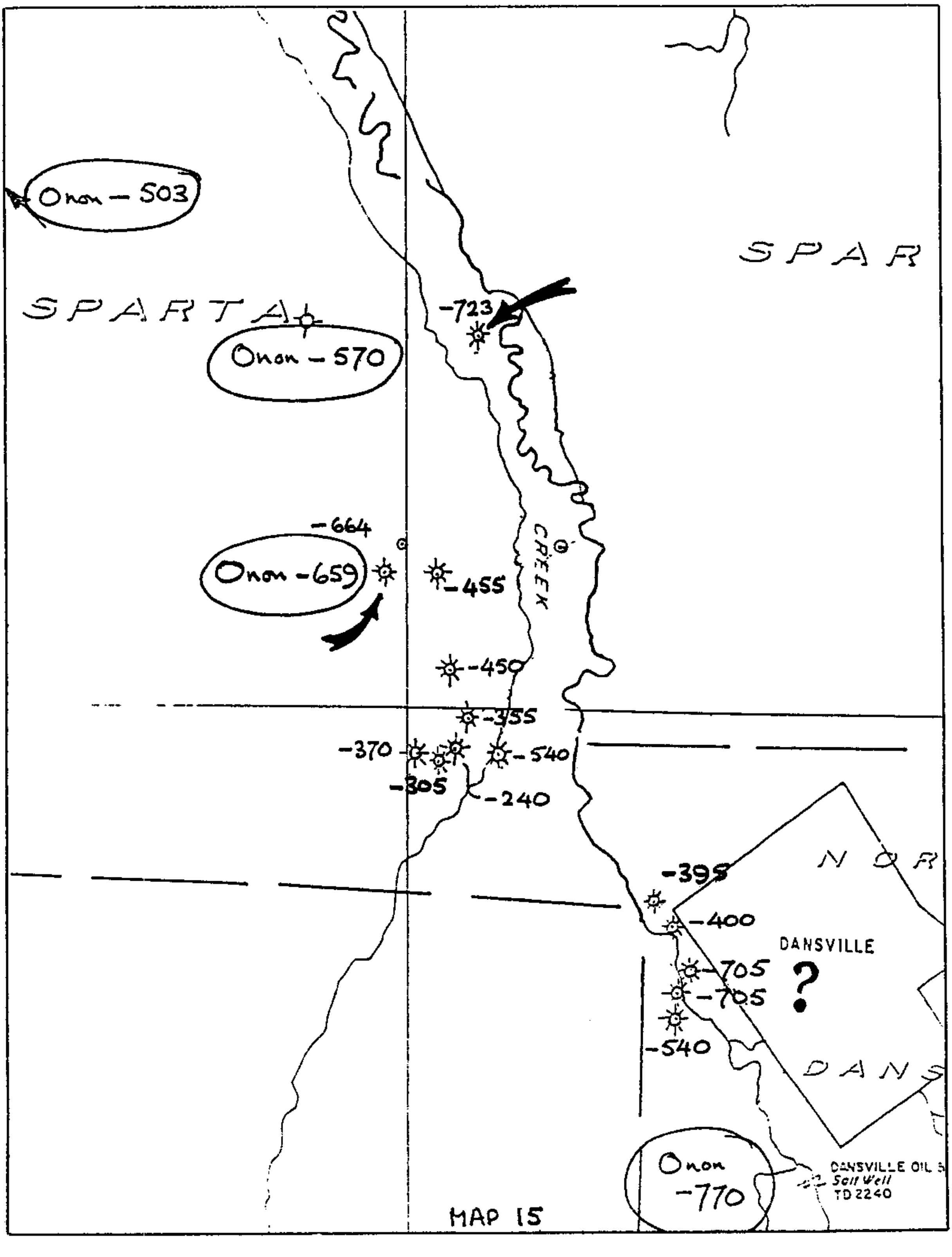
The Dansville shale-gas field: recorded wells.



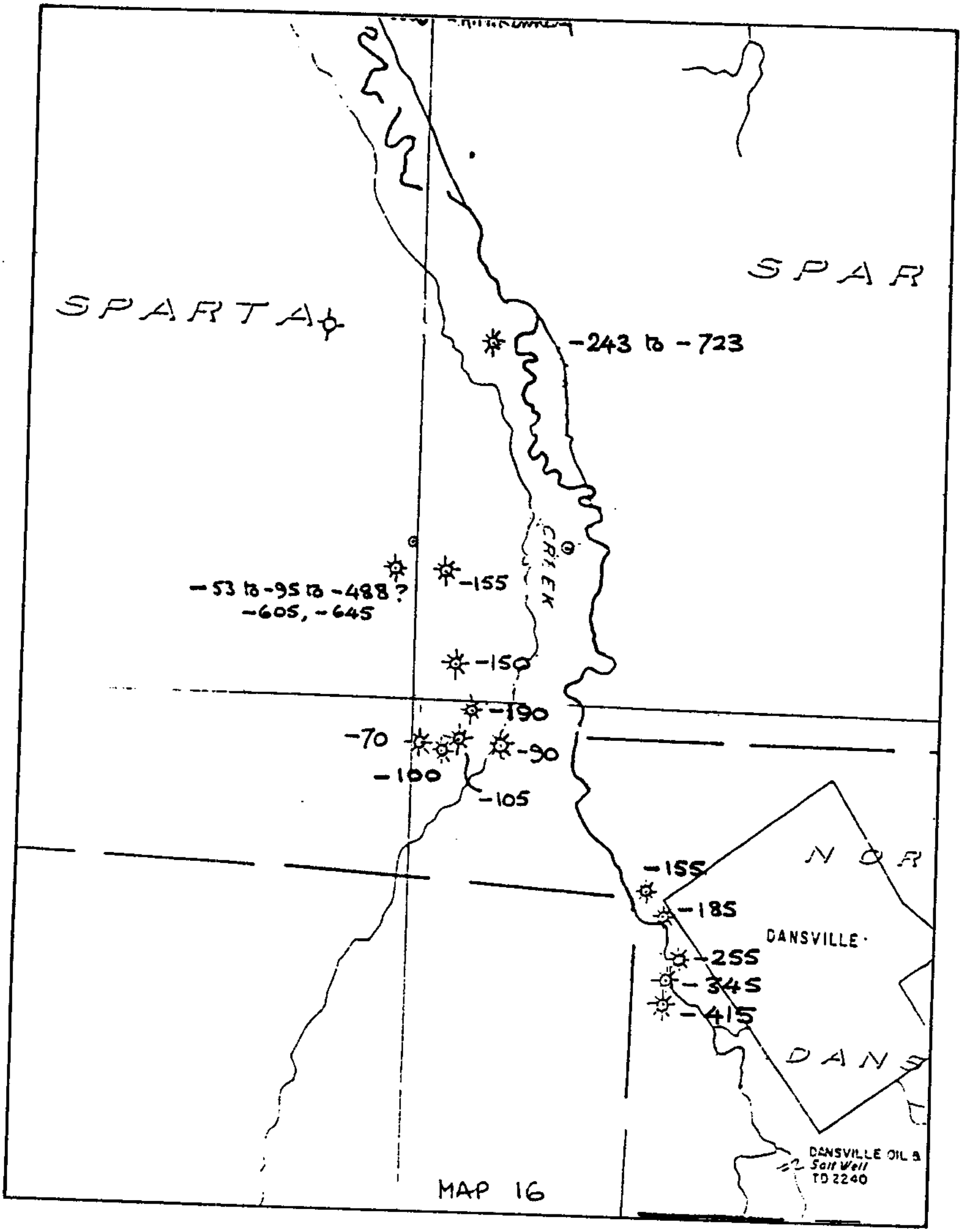
The Dansville shale-gas field: tax-map wells.



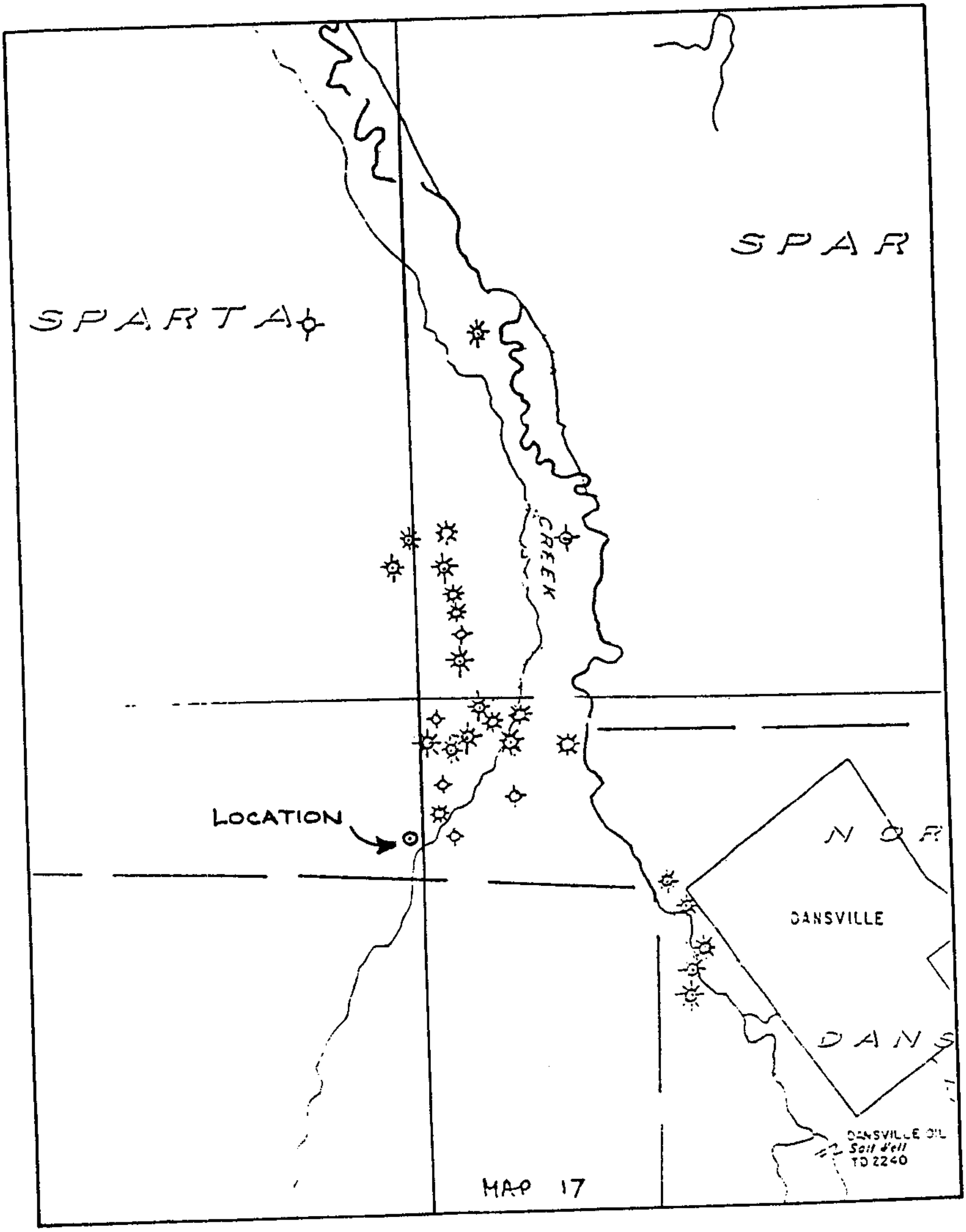
The Dansville shale-gas field: wells reaching the Onondaga.



The Dansville shale-gas field: depths reached (only arrowed wells penetrated Marcellus).



The Dansville shale-gas field: depths of gas production.



The Dansville shale-gas field: location of Meter no. 1 well.

DAILY DRILLING REPORT
METER, KENNEDY, HOWE UNIT #1 WELL

8-30-80: Grading road and location.

9-3-80 : Location ready.

9-4-80 : Moving in rotary tools.

9-5-80 : Rigging up.

9-6-80 : Drilling at 415'. Ran 33' of 11 3/4" casing set at 35'.

9-7-80 : Depth 520'. Going in hole with drill pipe to drill cement and guide shoe. Ran 503' of 8 5/8" casing set at 505' Cemented with 140 sacks Class A Common, 3% calcium chloride. Good cement returns to surface. Plug down at 3:00 pm.

9-8-80 : Driller's TD 1615'. Preparing to log sample tops. Tully 1047'. Onondaga 1599'. Show of gas and salt water at 1017' and show of gas on Baroid unit at 1560'.

9-9-80 : Moving in cable tools to run 4 1/2" casing. Slight show of gas. Logged by Schlumberger. Ran gamma ray, density, caliper, neutron, sonic, lateral log and audio. Log TD 1638'. Found fluid level at 627'.

9-10-80 : Wellhead installed. Drilling completed. Ran 1642' of 4 1/2" casing, set at 1640. Tagged bottom 1643'. Cemented casing with 330 sacks. Started with 180 sacks of regular Pozmix with 1/2 pound Flocele per sack. Tailed in with 150 sacks of Thixotropic. Plug down at 6:15 pm. Float held. Good cement returns to surface.

COMPILATION OF MONTHLY REPORTS
DANSVILLE PROSPECT
METER #1 WELL
(OCT. 1980-JAN. 1981)

October 31, 1980

Awaiting stimulation which is scheduled for November 10, 1980.

November 30, 1980

The Meter #1 Well was broken down on 11/5/80 and produced a small flow of gas after clean up.

The well was foam fraced on 11/10/80. After nine days of clean up (swabbing) the well had an estimated flow rate of 67 MSCFD. Presently the well is being production tested.

December 31, 1980

The Modified Isochronal Test was performed on the Meter #1 on 11/28/80. There is some question as to the validity of the results; subsequent to the test several individuals were found to be tampering with the well. Tampering may have taken place earlier as well. DA&M is looking into this further.

January 31. 1981

Consolidated Gas Supply Corporation conducted an Open Flow Test on the Meter #1 Well on January 16, 1981 which yielded a stabilized gas flow of 411 MCFD. This confirms the invalidity of the Modified Isochronal Test run on 11/28/80. A second Modified Isochronal Test and Build-up Test will be conducted during February, 1981.

February 29, 1981

A second modified isochronal test was conducted on 2/11/81. Stabilized shut-in pressure of 703 psig confirms the invalidity of the initial test. The absolute open flow of the Meter No. 1 Well was calculated at 95 MCFD. We await confirmation from Consolidated Gas Supply Corporation that they will purchase the production from the Meter well.

APPENDIX II 3.4

COMPLETION REPORT
DANSVILLE PROSPECT
METER #1 WELL
(NOV. 5, 1980-MAR. 4, 1981)

11-5-80: Swabbed 4 1/2" casing to TD. Spotted acid. Perforated 4 1/2" casing with 20 shots. Broke down formation and ran perf balls. Breakdown at 1750 psi. Treated at 1600 psi. Pressure increased to maximum of 1900 psi after dropping perf balls. Pumping rate 9 bbls per minute. Instantaneous shut-in pressure 1350 psi. Job complete at 5:05 pm. Flowed back into Halliburton tank 15 bbls in 9 minutes. Shut in to rig down. Open well at 5:25 pm. Flowed back fluid and gas. Gradu-ally decreasing. 6:30 pm left location left well open.

11-6-80: 8:00 am making very small stream of water, heading up. Ran swab. Well making estimated 10 gallons per minute of water.

11-7-80: Swabbing. Recovering 10' of fluid per hour.

11-8-80: Casing pressure 70 psig in 14 hours. Swabbing. Recovering 2-3' of fluid per hour. very little gas.

11-10-80: Casing pressure 160 psig in 43 hours. Foam Frac: average treating pressure 2394 psi, average rate 6.25 bbls per minute, used 770,000 cu ft of nitrogen and 760 sacks of sand. Flowed well back after treatment. Strong blow back to 11 pm. Shut well in.

11-11-80: Casing pressure 1240 psig in 11 hours. Blew well back until 3:30 pm. Blowing steady with spray of water. Rigged up bailing machine. Found fluid at 800'.

11-12-80: Casing pressure 740 psig in 15 hours. Blew well for 1 hour. Recov-ered heavy spray. Swabbed well to 1320'.

11-13-80: Casing pressure 540 psig in 15 hours. Blew 1/2 hour, ran swab to total depth. Found TD at 1625'. Swabbed all day. Recovered fluid and fair amount of gas.

11-14-80: Casing pressure 465 psig in 15 hours from 2500' fluid. Swabbed. Recovered 30-40' of fluid per hour. Open flow test 116 MCF per day.

11-17-80: Casing pressure 620 psig in 64 hours. Found 300' of fluid. Measured TD 1624'. Ran sand pump. Recovered very little sand.

11-18-80: Casing pressure 435 psig in 17 hours. Swabbing. Recovered estimated 20' of fluid per hour. Checked TD 1531. Open flow test 106 MCF per day.

11-19-80: Casing pressure 370 psig in 15 hours. Found 100' of fluid in hole. Swabbed 15' per hour.

11-20-80: Casing pressure 345 psig in 15 hours. Found 70' of fluid in hole. Swabbed 20' per hour.

11-21-80: Casing pressure 320 psig in 15 hours. Found 70' of fluid in hole. Swabbing 10-20' of fluid per hour. Open flow test 67 MCF per day. Installed recording chart for pressure build up test.

11-22-80: Casing pressure 260 psig in 20 hours.

11-24-80: Casing pressure 385 psig in 63 hours.

11-28-80: Casing pressure 522 psig dead weight test in 160 hours. Ran modified isochronal test. Final flowing pressure 45 psig through 1/2" orifice. Installed 1/16" orifice for stabilization rate.

11-29-80: 12:30 pm casing pressure 220 psig dead weight test. Well apparently stabilized at 190 psig through 1/16" choke, then increased to 220 psig. Installed 7-day chart for pressure build up test. Shut-in at 1:30 pm.

12-1-80 : Casing pressure 409 psig. Dead weight test 49 1/2 hours. Well not stabilized.

12-2-80 : Casing pressure 444 psig. Dead weight test 72 1/2 hours.

12-4-80 : Casing pressure 390 psig. (From chart) Removed pressure recorder, master meter bell. Shut-in.

12-17-80: Casing pressure 760 psig in 13 days. Moved in bailing machine and rigged up. Blew well 2 hours.

12-18-80: Casing pressure 490 psig in 16 hours. Blew well in 1 hour before running swab. Ran swab, recovered very little fluid. Took fluid sample for analysis. Birdwell logged. Ran gamma ray, temperature and spinner logs. Logs indicated gas coming from all perforations except for 1520 and 1522. Open flow test 200 MCF per day. Open 6 1/2 hours.

1-2-81 : Visit to well to take pressure reading. Found evidence of tampering the well. Located local farmer, Don Donovan, who owns several wells in area. He had blown well down to 50 psi and then shut it in to watch pressure build up. Made firm request that he not tamper with well in the future. Casing pressure 550 psig at 3:30 pm, probably 6 hours plus or minus after being blown down.

1-6-81 : Casing pressure 635 psig in 4 days. Took gas sample for analysis.

1-16-81 : Casing pressure 679 psig, dead weight test in 14 days. Met representatives of Consolidated Gas at wellsite. Took gas sample. Blew well down for open flow test. Open flow test stabilized at 411 MCF per day in 2 1/4 hours.

1-30-81 : Casing pressure 680 psig in 14 days.

2-5-81 : Casing pressure 705 psig in 20 days.

2-6-81 : Casing pressure 710 psig in 21 days.

2-7-81 : Casing pressure 720 psig in 22 days.

2-8-81 : Casing pressure 720+ psig in 23 days.

2-9-81 : Casing pressure 725 psig in 24 days.

2-10-81 : Casing pressure 730 psig in 25 days. Rigged up for flow test and installed pressure recorder. Chart reading 700 psig.

2-11-81 : Dead weight test 703 psig in 26 days. Ran Modified Isochronal Flow Test.

2-12-81 : Flowing pressure 372 psig through 3/32" choke in 24 hours.

2-13-81 : Final flowing pressure 308 psig through 3/32" choke. Shut in at 3:20 pm. Installed 7-day chart for pressure build up. Casing pressure 332 psig in 1 3/4 hours.

2-20-81 : Casing pressure 525 psig (chart, 575 psig ran gauge) in 164 hours. Changed chart.

3-1-81 : Casing pressure 600 psig, chart 16 days. Chart was twisted on spindel. Valid reading for first 2 days only, changed chart.

GAS WELL DELIVERABILITY TEST SUMMARY

APPENDIX II 3.5

GENERAL DATA

WELL NAME No. 1 Meter, Kennedy, Howe Unit — LOCATION Livingston Co. W___

FIELD OR AREA Dansville Prospect — ELEVATION (Gr.) 903 (KB) ___ ft

POOL OR ZONE Marcellus Shale — RESERVOIR TEMPERATURE 80 °F

PERF./~~OPEN HOLE~~ INTERVAL 1332'-1617.5' (20 holes) ft (KB)

CASING ID 4.052 in TUBING ID ___ in OD 4.50 in PACKER ___ ft (KB)

RESERVOIR GAS PROPERTIES: G 0.60 est P_c ___ T_c ___ MOL %: N_2 ___ CO_2 ___ H_2S ___

LICENSEE ___ OPERATOR (Co) Donohue Anstey & Morrill

TYPE OF TEST Modified Isochronal — FINAL DATE OF TEST Feb. 12 19 81

PRODUCTION DATA

RATE NO.	DURATION hours	GAS PRODUCTION Mscfd	CONDENSATE PRODUCTION Bbl/d	COND./GAS RATIO Bbl/Mscf	GAS-EQUIVALENT OF CONDENSATE Mscfd	TOTAL PRODUCTION-RATE Mscfd	WATER PRODUCTION Bbl/d	WATER/GAS RATIO Bbl/MMscf
1	1	129	Odor			129	0	
2	1	228	Odor			228	0	
3	1	662	Odor			662	0	
4	1	667	Odor			667	0	
EXTENDED RATE	14	72	Odor			72	0	

GAS PRODUCED THROUGH: Casing ~~TUBING~~ [X] ANNULUS [ ] TO: PIPE LINE [ ] VENT [X] FLARE [ ]

FLARE STACK HEIGHT ___ ft DIAMETER ___ in

TOTAL VOLUME OF GAS PRODUCED DURING CLEANUP AND TEST ___ Mscf

EQUIPMENT LIST

- LINE HEATER [ ]
- L.P. SEPARATOR [ ]
- H.P. SEPARATOR [ ]
- CRITICAL FLOW PROVER [X]
- ORIFICE METER [ ]
- LIQUID STORAGE TANK [ ]
- ___ [ ]
- ___ [ ]
- ___ [ ]

REMARKS

STABILIZED SHUT-IN RESERVOIR PRESSURE ($\bar{p}_R$) 743 psia

ABSOLUTE OPEN FLOW POTENTIAL 95 Mscfd

WELLHEAD OPEN FLOW POTENTIAL N/A Mscfd

GAS WELL DELIVERABILITY TEST – FIELD NOTES

WELL NAME No. 1 Meter, Kennedy, Howe Unit LOCATION Livingston Co., NY W

FIELD OR AREA Dansville Prospect POOL OR ZONE Marcellus Shale

PERF./XXXXXXXX INTERVAL 1332'-1617.5(20 Holes) PRODUCING THROUGH: ~~XXXXXXXXXXXXXXXXXXXX~~ 4 1/2" casing

WELL BLOWN FOR N.A. minutes SPRAY: WATER/CONDENSATE CLEAR IN minutes

DATE SHUT-IN Jan. 16 19 81 TIME 12:45 PM TOTAL SHUT-IN TIME 620 hours

SHUT-IN NO. 1 (INITIAL)

DATE	TIME	CUMULATIVE SHUT-IN TIME hours	WELLHEAD PRESSURE psig		WELLHEAD TEMPERATURE °F
			TUBING	CASING	
1-30-81				680 (gauge)	
2-5-81				705 (gauge)	
2-11-81	8:25A	620		703	50

REMARKS

All pressures are DWT unless otherwise indicated

FLOW NO. 1 WELL OPENED AT 9:15 AM/~~PM~~ 2-11 19 81

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig		WELLHEAD TEMPERATURE °F	METER OR PROVER DATA		
			TUBING	CASING		STATIC PRESSURE psig	DIFFERENTIAL inches H_2O	TEMPERATURE °F
2-11-81	9:15A	–		703	50	703		50
	9:30	0.25		693	49	693		49
	9:45	0.50		686	49	686		49
	10:00	0.75		682	50	682		50
	10:15	1.00		679	50	679		50

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 3/32 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, °F LP SEP. psig, °F

CONDENSATE PRODUCTION RATE Strong Odor Bbl per hour TOTAL Bbl

WATER PRODUCTION RATE – Bbl per hour TOTAL Bbl

FINAL FLOWING WELLHEAD PRESSURE: TUBING CASING 679 psig

WELL SHUT-IN AT 10:15 AM/~~PM~~ 2-11 19 81 TOTAL FLOW TIME 1 hours

NOTE: FLOWING WELLHEAD PRESSURES AND TEMPERATURES MUST BE [obscured] EAM OF ANY CHOKING DEVICE

GAS WELL DELIVERABILITY TEST - FIELD NOTES

SHUT-IN NO. 2 (INTERMEDIATE)

DATE	TIME	CUMULATIVE SHUT-IN TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F
2-11-81	10:15A	-		679	50
	10:30	0.25		683	54
	10:45	0.50		685	56
	11:00	0.75		687	56
	11:15	1.00		688	56

REMARKS

FLOW NO. 2 WELL OPENED AT 11:15 AM/~~PM~~ 2-11 19 81

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F	METER OR PROVER DATA STATIC PRESSURE psig	METER OR PROVER DATA DIFFERENTIAL inches H_2O	METER OR PROVER DATA TEMPERATURE °F
2-11-81	11:15A	-		688	56	688		56
	11:30	0.25		668	50	668		50
	11:45	0.50		655	50	655		50
	12:00	0.75		647	50	647		50
	12:15P	1.00		638	50	638		50

ORIFICE SIZE 1/8 inches

METER RUN OR PROVER SIZE 2 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ____ °F   LP SEP ____ psig, ____ °F

CONDENSATE PRODUCTION RATE Strong odor bbl per hour   TOTAL ____ bbl

WATER PRODUCTION RATE - bbl per hour   TOTAL ____ bbl

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 638 psig

TOTAL FLOW TIME 1 hours

WELL SHUT-IN AT 12:15 ~~AM~~/PM 2-11 19 81

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GAS WELL DELIVERABILITY TEST – FIELD NOTES

SHUT-IN NO. 3 (INTERMEDIATE)

DATE	TIME	CUMULATIVE SHUT-IN TIME hours	WELLHEAD PRESSURE psig		WELLHEAD TEMPERATURE °F
			TUBING	CASING	
2-11-81	12:15P	-		638	50
	12:30	0.25		647	51
	12:45	0.50		652	47
	1:00	0.75		655	41
	1:15	1.00		658	39

REMARKS

FLOW NO. 3 WELL OPENED AT 1:15 ~~AM~~ / PM 2-11 19 81

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig		WELLHEAD TEMPERATURE °F	METER OR PROVER DATA		
			TUBING	CASING		STATIC PRESSURE psig	DIFFERENTIAL inches H_2O	TEMPERATURE °F
2-11-81	1:15P	-		658	39	658		39
	1:30	0.25		575	48	575		48
	1:45	0.50		525	48	525		48
	2:00	0.75		484	48	484		48
	2:15	1.00		446	48	446		48

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 1/4 inches

SEPARATOR CONDITIONS: HP SEP. N. A. psig, ____ °F LP SEP ____ psig, ____ °F

CONDENSATE PRODUCTION RATE Strong Odor Bbl per hour TOTAL ____ Bbl

WATER PRODUCTION RATE - Bbl per hour TOTAL ____ Bbl

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 446 psig

WELL SHUT-IN AT 2:15 XXA / PM 2-11 19 81 TOTAL FLOW TIME 1 hours

TI-60

GAS WELL DELIVERABILITY TEST - FIELD NOTES

SHUT-IN NO. 4 (INTERMEDIATE)

DATE	TIME	CUMULATIVE SHUT-IN TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F
2-11-81	2:15P	-		446	48
	2:30	0.25		487	42
	2:45	0.50		509	39
	3:00	0.75		524	36
	3:15	1.00		535	34

REMARKS

FLOW NO. 4 WELL OPENED AT 3:15 ~~AM~~ / PM 2-11 19 81

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F	METER OR PROVER DATA STATIC PRESSURE psig	DIFFERENTIAL inches H_2O	TEMPERATURE °F
2-11-81	3:15P	-		535	34	535		34
	3:30	0.25		270	48	270		48
	3:45	0.50		177	48	177		48
	4:00	0.75		131	48	131		48
	4:15	1.00		103	48	103		48

METER RUN OR PROVER SIZE 2 inches

ORIFICE SIZE 1/2 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ____ °F

LP SEP ____ psig, ____ °F

CONDENSATE PRODUCTION RATE Strong Odor bbl per hour

TOTAL ____ bbl

WATER PRODUCTION RATE - bbl per hour

TOTAL ____ bbl

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 103 psig

WELL SHUT-IN AT ____ AM/PM ____ 19 ____

TOTAL FLOW TIME 1 hours

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GAS WELL DELIVERABILITY TEST - FIELD NOTES

~~XXXXXXXXXXXXXXXX~~ FLOW NO. 5 TO STABILIZATION

Date	Time	Cum. Hrs.		Casing psig		Prover psig		Temp. °F
2-11-81	4:15P	-						
	4:30	0.25				103		48
	4:45	0.50				189		39
2-12-81	12:45P	20.50				228		38
	1:15	21.00				382		36
	1:45	21.50				380		36
	2:15	22.00				378		37
	3:45	23.50				377		36
	4:15	24.00				373		31
2-13-81	1:45P	45.50				372		29
	3:15P	47.00				316		46
						308		46

Note: Assume stabilization occurred between 6:00 AM & 8:00 AM on 2-12-81 (see recording chart). At this point pressure had decreased slightly from the maximum attained about 1:00 AM & would be consistent with other flow test interpretations.

Stabilized pressure = 373 psig (corr. to DWT).

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 3/32 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ____ °F LP SEP. ____ psig, ____ °F

CONDENSATE PRODUCTION RATE Strong odor. Found 2" build up of hydrates behind plate. Bbl per hour TOTAL ____ Bbl

WATER PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 308 psig

WELL SHUT-IN AT 3:20 ~~AM~~/PM 2-13 19 81 TOTAL FLOW TIME 47 hours

FINAL SHUT-IN WELLHEAD PRESSURE: TUBING ____ CASING 662 psig 11:00 AM, 3/9/81

DURATION OF FINAL SHUT-IN 572 hours TESTED BY (CO.) Arlington Exploration Company

GAS WELL DELIVERABILITY TEST CALCULATIONS - FLOW RATES

(BASE CONDITIONS = 14.65 psia and 60°F)

CRITICAL FLOW PROVER $q = 10^{-3}\ C\ P\ F_{tf}\ F_g\ F_{pv}$

RATE NO.	PROVER SIZE inches	ORIFICE DIAMETER inches	BASIC ORIFICE COEFFICIENT (C) Mscfd/lb.	STATIC PRESSURE (P) psia	FLOW. TEMP. FACTOR F_{tf}	SPECIFIC GRAVITY FACTOR F_g	SUPERCOMP. FACTOR F_{pv}	FLOW RATE q ~~M~~Mscfd
1	2	3/32	0.1863	694	1.0000	1.0000	1.0000	129
2	2	1/8	0.3499	653	"	"	"	228
3	2	1/4	1.4360	461	"	"	"	662
4	2	1/2	5.6530	118	"	"	"	667
5	2	3/32	0.1863	388	"	"	"	72

GAS WELL DELIVERABILITY TEST CALCULATIONS

(BASE CONDITIONS = 14.65 psia and 60°F)

WELL NAME No. 1 Meter, Kennedy, Howe Unit LOCATION Livingston Co., NY W__

POOL OR ZONE Marcellus Shale FINAL DATE OF TEST ____ 19__

SIMPLIFIED ANALYSIS

	DURATION hours	SANDFACE PRESSURE psia	CALC.	MEAS.	$p^2 \times 10^{-3}$ psia^2	$\Delta p^2 \times 10^{-3}$ psia^2	FLOW RATE (q) ~~M~~Mscfd
INITIAL SHUT-IN	620	743	x		552		
FLOW 1	1	718	x		516	36	129
SHUT-IN	1	728	x		530		
FLOW 2	1	676	x		457	73	228
SHUT-IN	1	696	x		484		
FLOW 3	1	477	x		228	256	662
SHUT-IN	1	569	x		324		
FLOW 4	1	122	x		15	309	667
EXTENDED FLOW	14	402	x		162	390	72
FINAL SHUT-IN							

RESULTS

$q = C\left(\bar{p}_R^2 - p_{wf}^2\right)^n$

slope n = 0.80

$\bar{p}_R$ = 743 psia

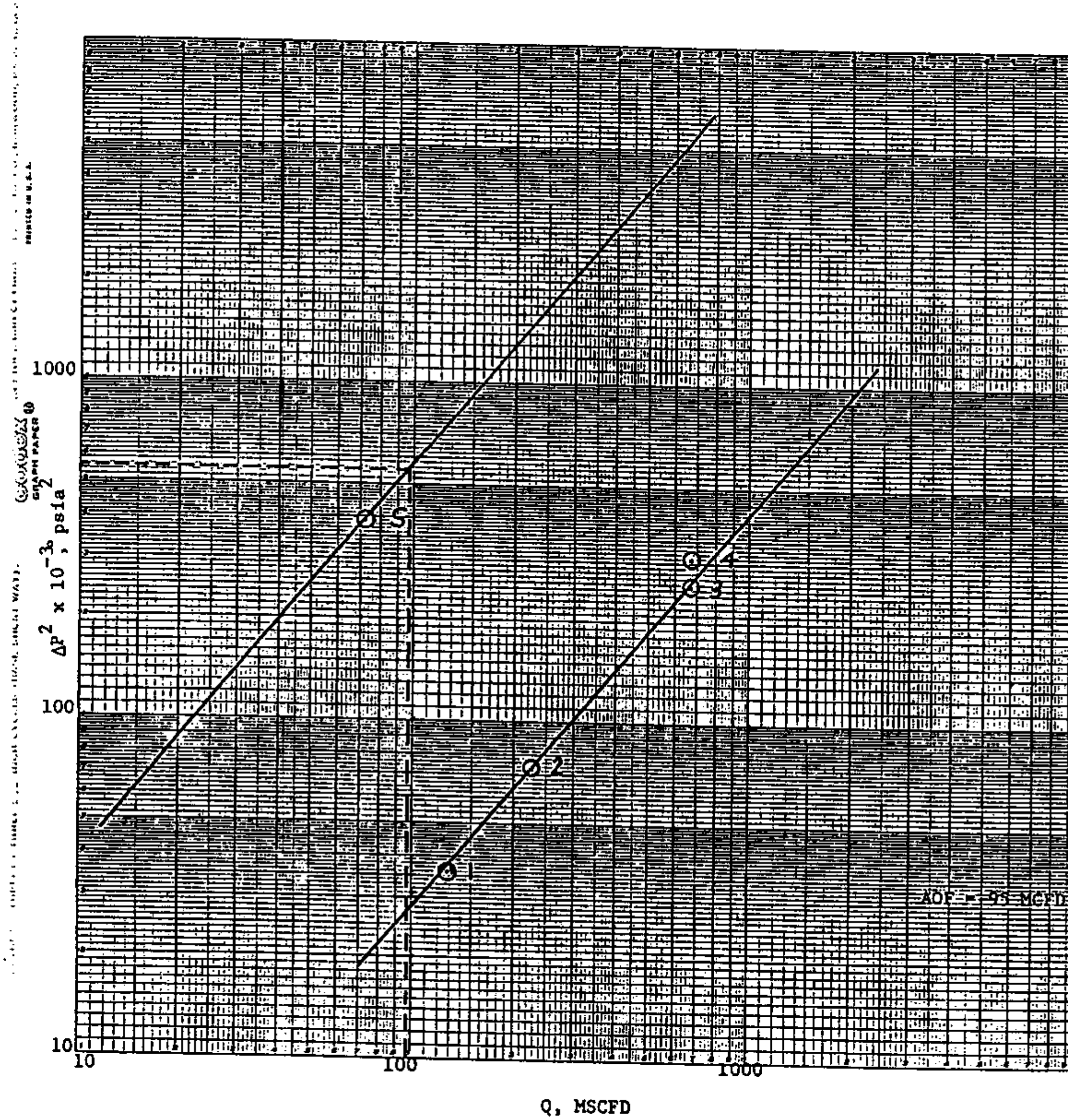
$C = \dfrac{q}{\left(\bar{p}_R^2 - p_{wf}^2\right)^n}$

= 0.61 MCFD/psi^2

AOF (~~MMXXXX~~)

= 95 MCFD

MODIFIED ISOCHRONAL TEST
METER NO. 1 WELL
MARCELLUS SHALE
FEBRUARY 12, 1981



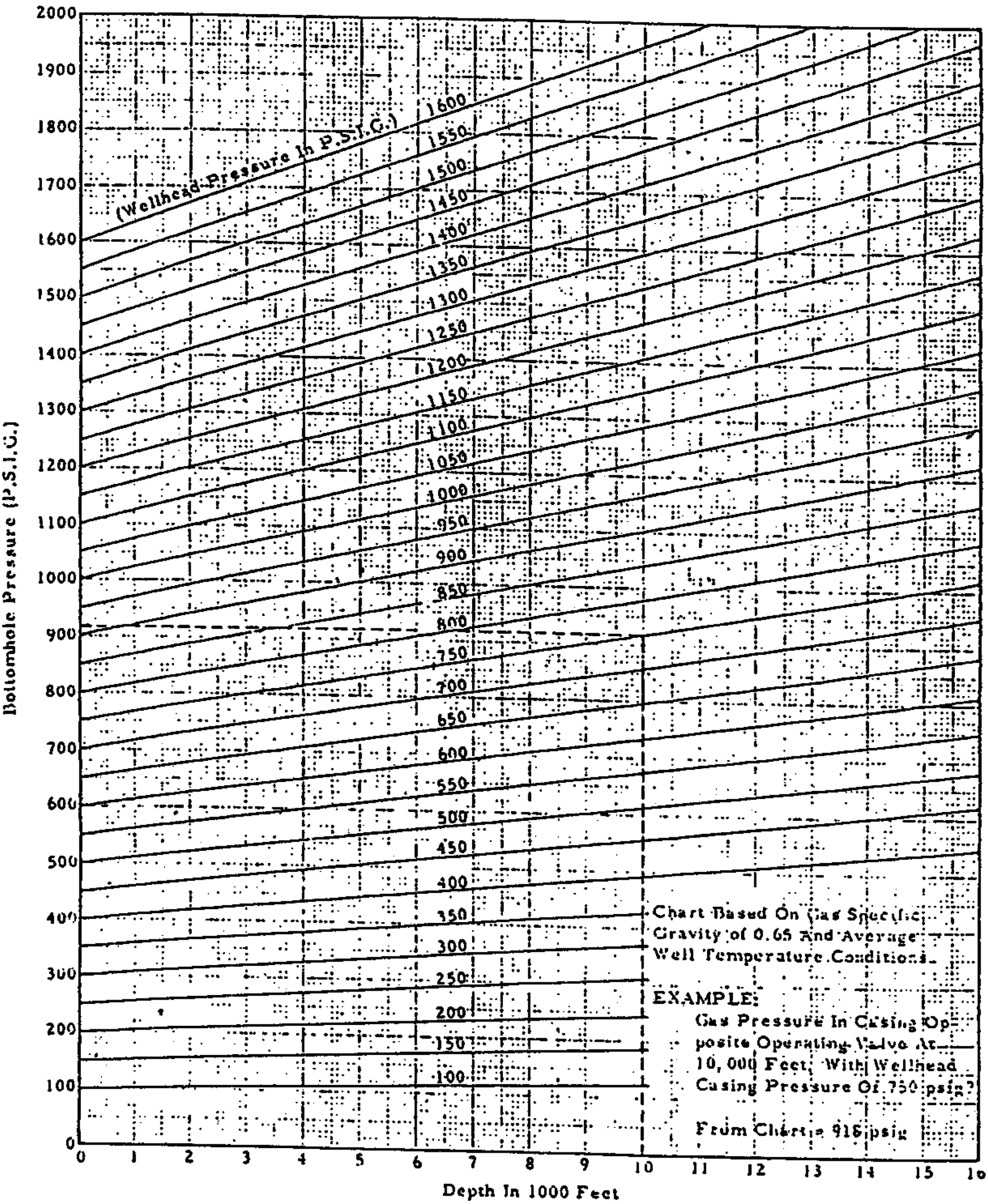
Size of Orifice (inches)	2-Inch Pipe C	Size of Orifice (inches)	4-Inch Pipe C
1/16	0.0846	1/4	1.384
3/32	0.1863	3/8	3.110
1/8	0.3499	1/2	5.564
3/16	0.8035	5/8	8.668
7/32	1.1090	3/4	12.422
1/4	1.4360	7/8	16.893
5/16	2.2080	1	22.007
3/8	3.1420	1 1/8	27.721
7/16	4.5030	1 1/4	34.229
1/2	5.6530	1 3/8	41.210
5/8	8.5500	1 1/2	49.106
3/4	12.4900	1 3/4	67.082
7/8	17.1800	2	88.628
1	22.5800	2 1/4	113.617
1 1/8	28.9200	2 1/2	142.490
1 1/4	36.5100	2 3/4	176.420
1 3/8	44.8600	3	216.790
1 1/2	55.6400		

TABLE 6-1 ORIFICE COEFFICIENTS FOR 2" AND 4" FLOW PROVERS

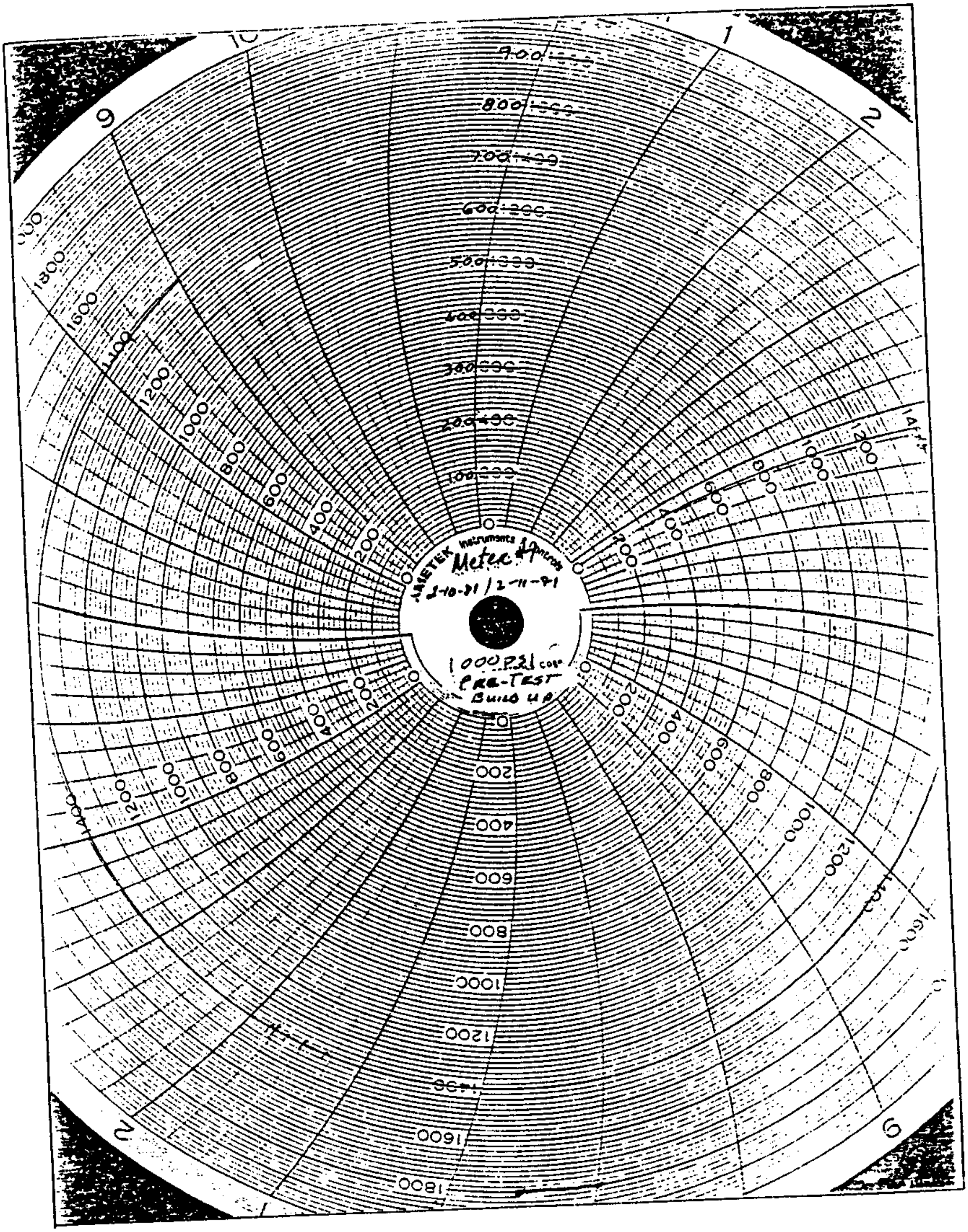
From Railroad Commission of Texas (1950)

CHART NO. V

PRESSURE DUE TO GAS COLUMN WEIGHT

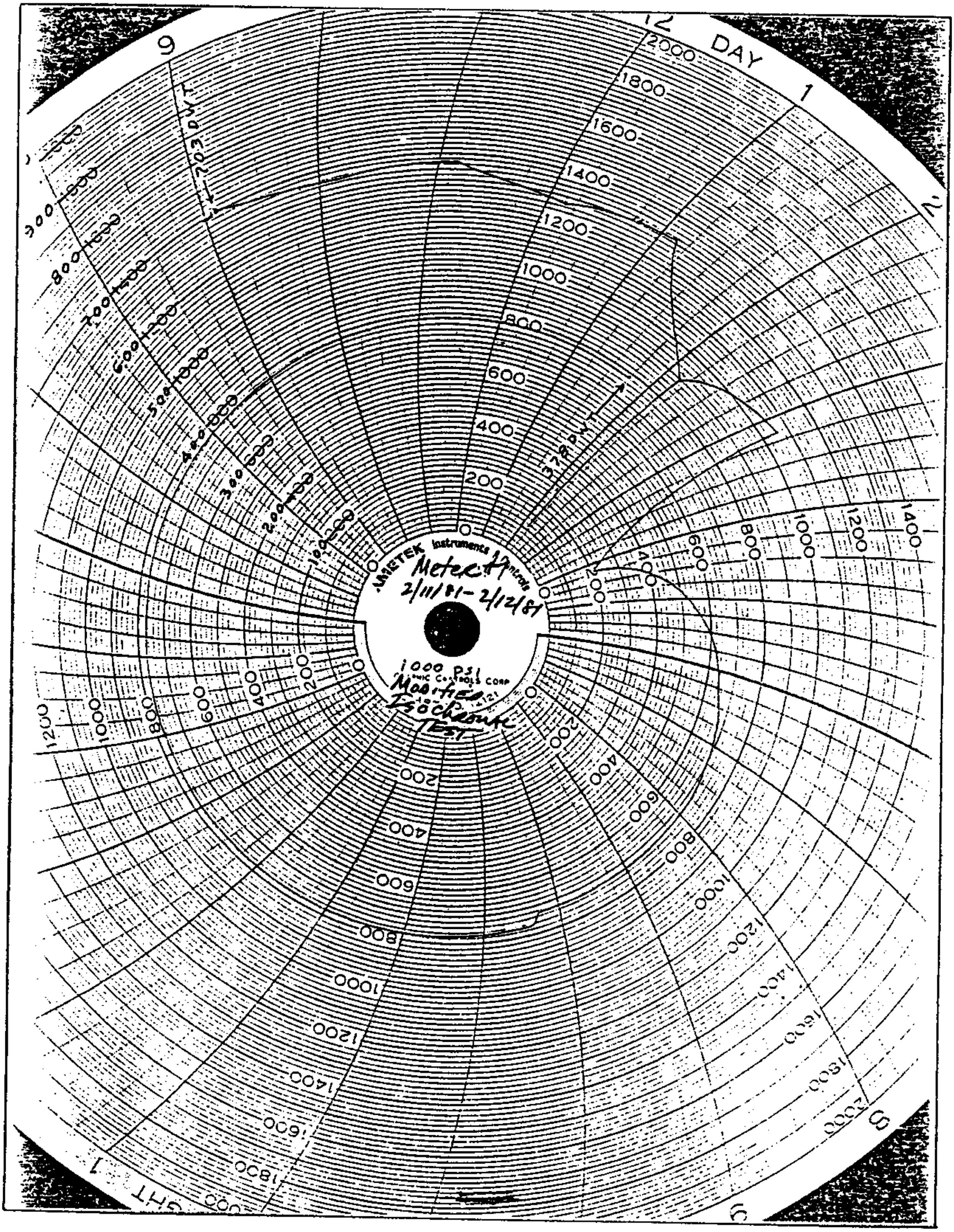


Pressure Recording Chart



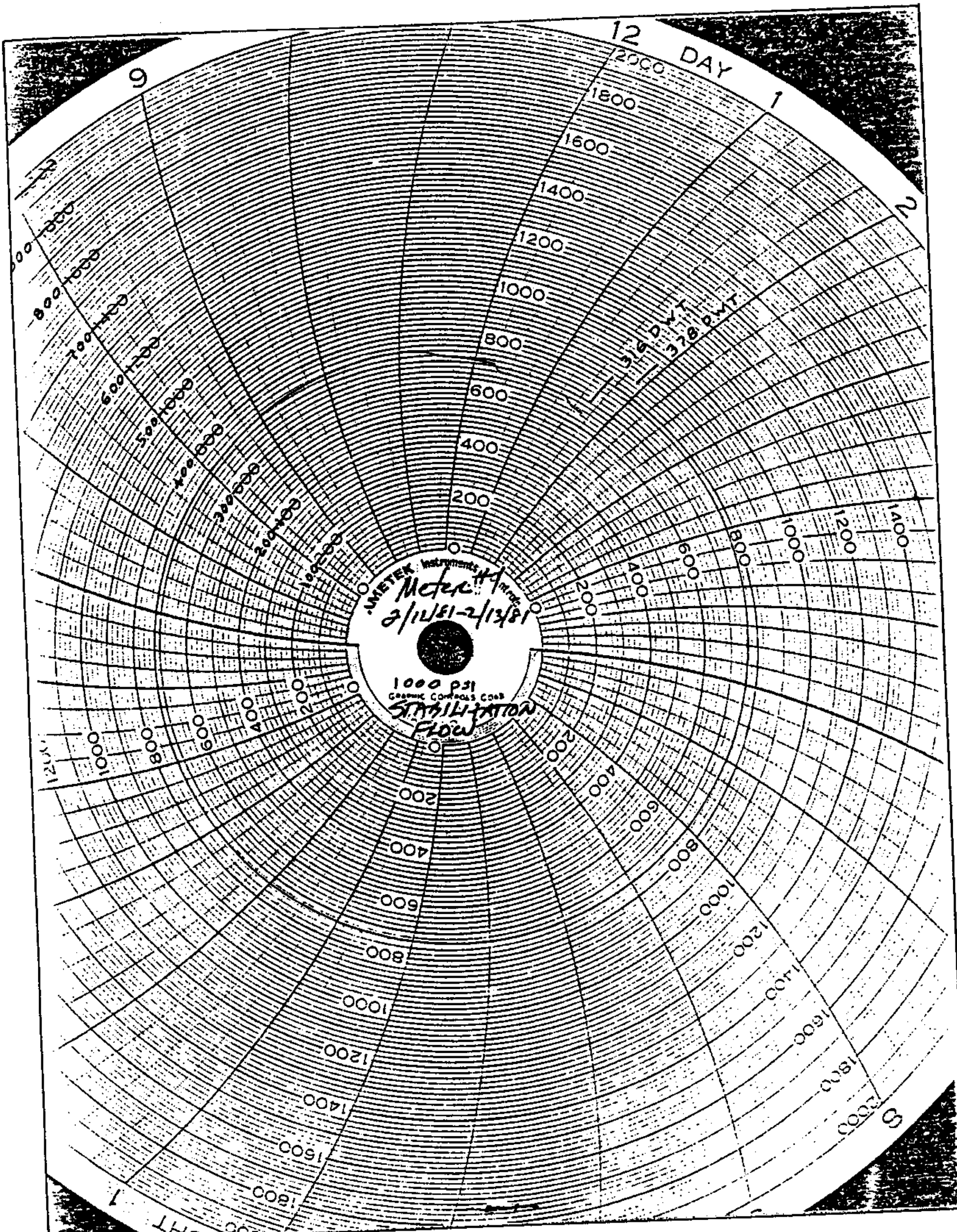
Pre-Test Build-up - Meter #1 Performed 2/10/81-2/11/81

Pressure Recording Chart



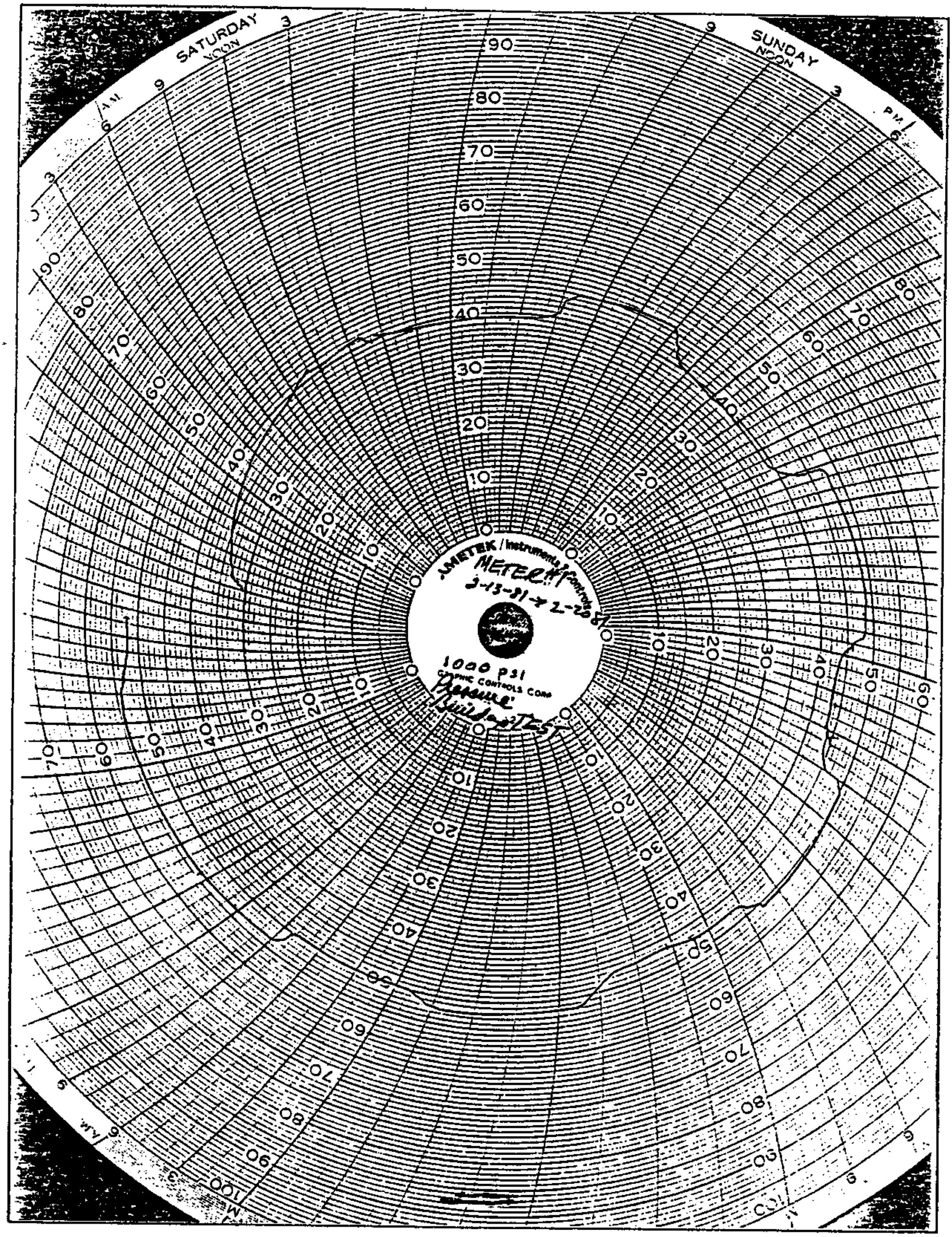
Modified Isochronal Test - Meter #1 Performed 2/11/81-2/12/81

Pressure Recording Chart

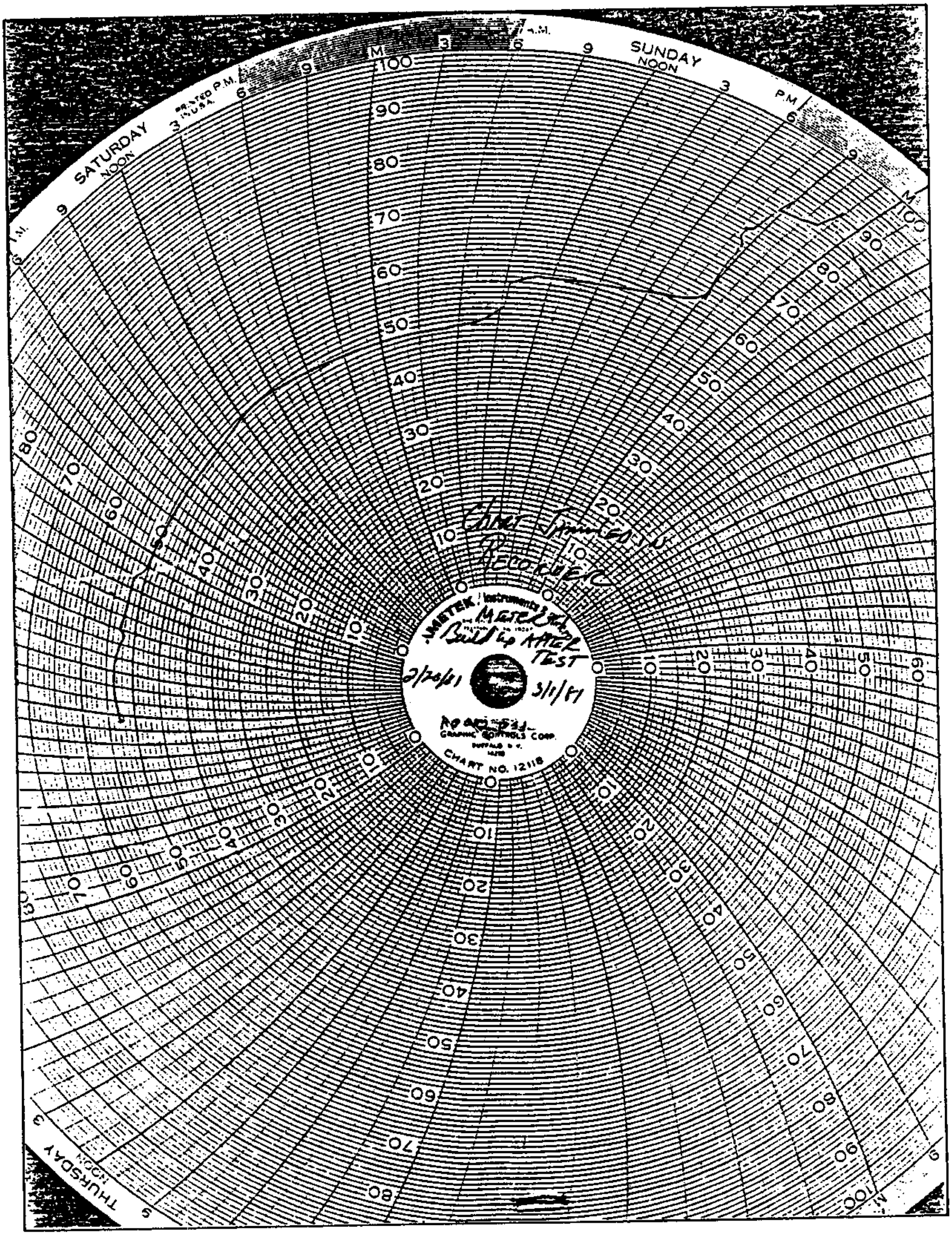


Stabilization Flow - Meter #1 Performed 2/12/81-2/13/81

Pressure Recording Chart

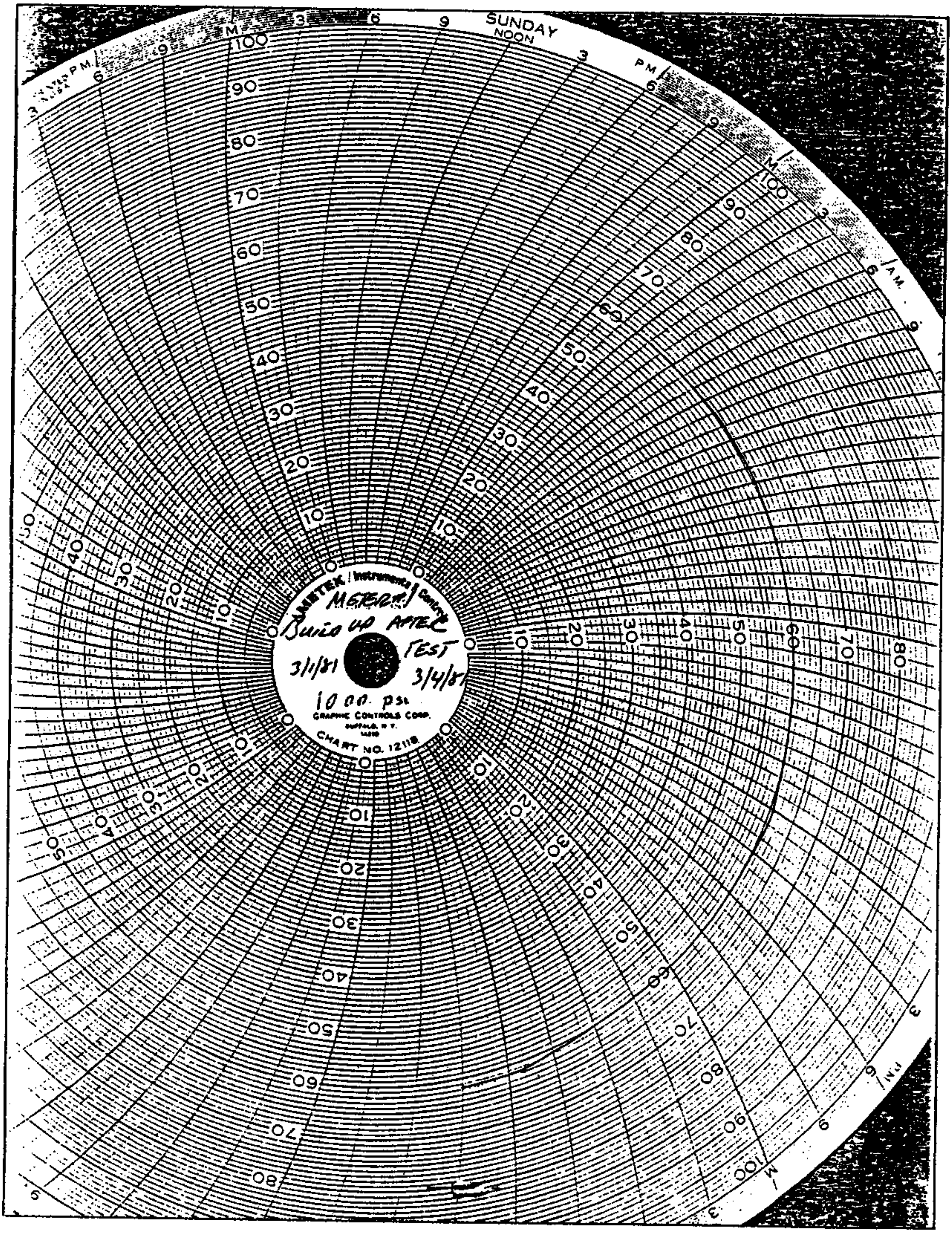


Pressure Build-up Test - Meter #1 Performed 2/13/81-2/20/81



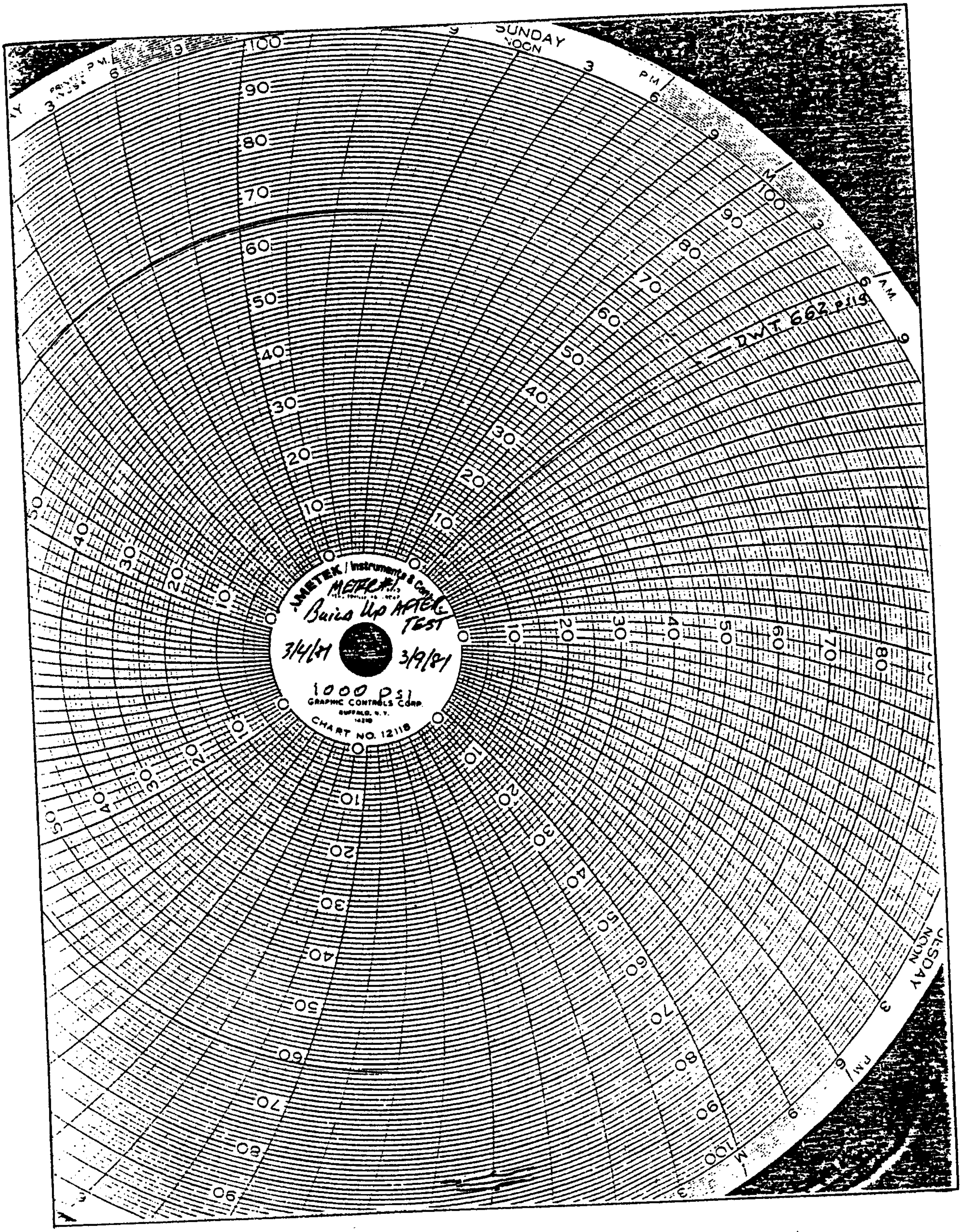
Build-up After Test - Meter #1 Performed 2/20/81-3/1/81

Pressure Recording Chart



Build-up After Test - Meter #1 Performed 3/1/81-3/4/81

Pressure Recording Chart



Build-up After Test - Meter #1 Performed 3/4/81-3/9/81

EXPLORATION RATIONALE
NORTH CORNING PROSPECT
AMBROSE E. SCUDDER #1 WELL

1. The basic rationale for this location is a repeat of the Leach No. 1 well; this well found shale gas in what appears to be a rubblized conduit zone stratigraphically continuous over the area. Because of the presumed continuity, the detailed location of the well is probably not critical. However, our original choice was a simple offset to the Leach well, so that the scope for change was minimized.

2. No lease could be obtained on the Leach property. Confronted by choice of direction, we chose to move north; it is apparent from the well records that a down-to-the-south-east fault occurs somewhere between the Gailbert Scudder No. 2 and JVP Cass wells (see Map 9), and our object was to move toward the downthrown side of this fault.

3. Dr. Howard's lineament analysis is superimposed on the topo map (2000 ft. to 1 inch) in Map 10. Again the lineaments from satellite imagery are shown as heavy lines; the others are from aerial photography. It seems likely that the lineament labeled AA' is a surface expression of the deep fault. Our primary location marked on Map 9 is on this fault, where it is intersected by both a satellite lineament and an aerial lineament (Map 10).

4. Initial attempts to lease the primary location were unsuccessful. There was no problem with the Scudder property, but the location also requires the assent of many houselot-owners, who had suffered a bad experience with the Cass well. We therefore adopted the alternate location, in hopes that this would allow the required spacing of 660 ft. from the property boundaries. In the event, it transpired that no location can be chosen whose spacing is not a few feet short of this figure. We therefore considered an application for mandatory pooling of the houselots, but it became clear that this would take too long. Yet one more attempt to lease the houselots was finally successful, except in the case of the

Stramowski property; this situation allowed the alternate location as the final wellsite.

5. The alternate location remains close to the AA' lineament, but not to the other two. However, we are much more confident of the significance of the AA' lineament than of the others, because of the former's probable association with a known sub-surface fault. We are therefore content with the final location.

COMPILATION OF MONTHLY REPORTS
NORTH CORNING PROSPECT
SCUDDER #1 WELL

July 31, 1980

North Corning: Scudder No. 1

This well was spudded, at the alternate location given in the monthly report for June, on 21 July, 1980. Delays were encountered in drilling the surface hole, due to the unexpectedly hard materials. No gas indications were obtained down to 1200 ft, where the first core was started.

A small gas show (10-20 units) was recorded on the mudlogger at 1226 ft. The first core (1200-1230 ft) showed a small fractured zone, also at 1226. However, an immediate visual inspection of this zone revealed no obvious justification for accepting this as the stratigraphically-continuous conduit for which we were searching, and so the coring was continued for a further 30 ft. This second 30 ft showed no fractures and no gas indications. To cover the possibility that the well was located on a small graben between the Leach and Gailbert wells, drilling was continued for a further 40 ft below the cored interval; this also produced no gas shows.

Subsequently, the gamma-ray log showed that the fracturing at 1226 ft is indeed at the same stratigraphic level as the significant gas show in the Leach well. We therefore have a good core across this interval, but only an insignificant gas show. Attached is a montage of the dry-hole logs over the interval.

The hole is shut in, pending a more detailed investigation of the fractured zone.

August 31, 1980

North Corning: Scudder No. 1

This well remains behind pipe, as reported in last month's report. We propose to leave it so, until we have fractured the Erwin (Dann) well discussed below.

There are now six wells in the area west and north of Corning which have gas shows at the same stratigraphic level. Whether this level constitutes an economic conduit remains to be demonstrated. If it is so, the possibility remains that the Scudder well can be made productive by opening this zone horizontally. If it is not, the well will be plugged and abandoned.

Schlumberger report that the temperature log used in last month's montage was run with the wires crossed, and that decreases of temperature should be read as increases. The validity of the log is not affected.

September 30, 1980

No change (except that Schlumberger have now decided to stand by the original display of their temperature log).

DAILY DRILLING REPORT
AMBROSE E. SCUDDER #1 WELL

7-23-80: Presently drilling at 110'. Moved in and rigged up International Petroleum Service Company's (IPSCO) Rig #2. Spudded well at 8:00 pm, 7/22/80. Ran 52' of 11 3/4" conductor pipe and set at 50'.

7-24-80: Presently waiting on cement. Drilled to 508'. Ran 517' of 8 5/8" surface casing and set at 508'. Cemented with 140 sacks. Good cement return. Plug down at 3:30 pm, 7/24/80.

7-25-80: Presently shutdown for rig repairs. Drilled out under surface. Drilled to 1203'. Broke shear pin on pull down. Engineer called out from Sheffield, PA.

7-26-80: Presently going in hole for 2nd core. Rig repaired at 4 pm 7/25/80. Came out of hole with drill pipe. Rigged up core barrel, went in hole with core barrel and started coring at 11:50 pm 7/25/80. Cored to 1233' at 3:25 am, 7/26/80. Retrieved 1st core at 7:00 am, 7/26/80. Mud logger noted 10 units of gas at 1226'.

7-27-80: Waiting on logging truck. Cored to 1263'. Retrieved 2nd core at 5:00 pm, 7/26/80. (Total cored interval 1203'-1263'). Went in hole with drill bit and drilled to total depth of 1342' at 10:30 pm, 7/26/80. Birdwell logging truck due at 11:00 pm, 7/26/80. Truck did not arrive and a subsequent call at 3:00 am, 7/27/80 related that Birdwell would not be on location until pm 7/27/80. Called Schlumberger to perform logging work.

7-28-80: Opened hole — waiting on orders. Schlumberger arrived 11:15 am, 7/27/80. Ran dry suite of logs. Logging complete at 4:30 pm 7/27/80. Rigged down and moved out IPSCO.

7-29-80: Opened hole.

7-30-80: Installed wellhead and shut in for pressure build up.

EXPLORATION RATIONALE
ERWIN PROSPECT
ROBERT M. DANN #1 WELL

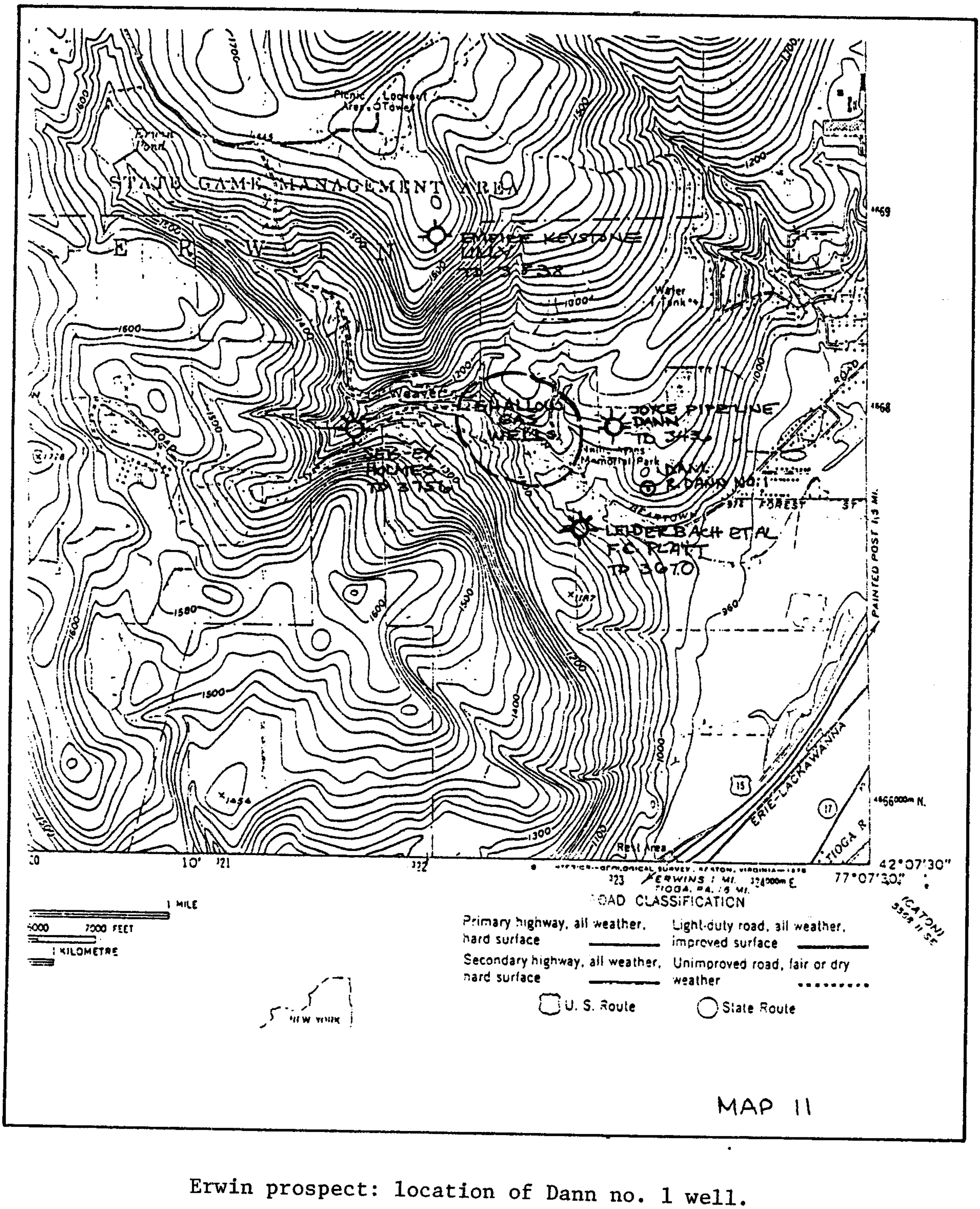
1. Map 11 shows the location of the new well, relative to several others in the area. Three Oriskany wells — the Holmes, the Dann and the Platt — had shows of gas in the shale; the Holmes was good enough to warrant completion in the shale, but mechanical difficulties finally precluded this. The area shown as "shallow gas wells" is said to contain four shallow wells which produced for a time. One of these has been located, and its depth established as 1320 ft; this would take it to the same stratigraphic level as the show in the Holmes well and one of the shows in the Dann well. This level is 1345 ft above the Tully in the Holmes well; in the North Corning area (discussed in the June report) the major show is at 1350 ft above the Tully, and we are postulating that a rubbleized conduit bed extends throughout the area between N. Corning and Erwin.

2. It remains to assure ourselves of a natural fracture system in the shale. It is believed that the Holmes well is located on a horst; the problem is therefore to find the down-to-the-south fault bounding this horst. The driller's records show a significant increase in the Tully-Onondaga interval between the Dann and Platt wells, and an anomalously thick Onondaga in the latter. These facts allow two interpretations: that the fault is a reverse fault passing through the Platt well, or that the fault is a normal fault to the north of the Platt well — with depositional thickening in the Onondaga-Tully interval. We have seen examples of both these situations, and of the Onondaga thickening on the downthrown side of faults, in the study area; there is no evidence to allow us to choose between the two interpretations in this case. The matter is of some importance, because if it is a reverse fault we would tend to prefer a location south of the Platt well, whereas if it is a normal fault we would prefer a location on trend or to the north.

3. With nothing else to guide us we considered it prudent to stay between the

two known gas shows, rather than to move south into the unknown. This approach was confirmed by the land situation; a good location with a straightforward lease position, was found to the north of the houselots on Beartown Road. This is the location shown on Map 11. Of the four wells to be drilled in the program, only this one allowed a straightforward leasing operation and easy access.

4. We estimate the fault trend in this area as about 60^{o} east of north, which places the Platt well and the new location in equivalent positions. If the fault is a reverse fault and the Platt well cuts it between the Tully and the Onondaga, the new location is north of the fault at the prospective Rhinestreet level. If the fault is a normal fault and between the Platt and Dann wells, the new location is less than a thousand feet from the fault on the downthrown side, and hence in a position likely to evince fractures in the shale. On balance, we are well content with this location.



Erwin prospect: location of Dann no. 1 well.

COMPILATION OF MONTHLY REPORTS
ERWIN PROSPECT
DANN #1 WELL

August 31, 1980

Erwin: Dann No. 1

After continued problems with the surface gravel reported last month, this well proceeded to its planned TD of 1400 ft. A good gas show was obtained at the predicted depth of 1074 ft and two smaller shows shallow.

Complications persisted with the surface gravel. The indications are that the looseness of the gravel defeated a good cement job, and that water continued to enter the hole at the base of the surface casing. Rapid action was required to ensure that the level of standing water in the hole did not rise to the point of gas entry; this was successful (although the possibility remains of some lesser formation damage by water running down the walls of the hole). At present the hole is cased down to just above the gas entry, and filled to just below; the intention is to seal the filling below, and so to allow stimulation of the productive interval in the open hole.

Before stimulating, however, we are proceeding to obtain some measure of the natural flow. The well is presently being connected to Corning Natural's low-pressure system with a temporary link, and the sale of gas (at $2.40/mcf) will commence early in September. We do not expect the sustained natural production to be major, of course, but it is important to NYSERDA's objectives in this program that the natural potential (and hence the economics of unstimulated wells) should be known.

September 30, 1980

Erwin: Dann No. 1

The well was connected to the local gas-distribution line for most of the month. Although demand was small and the pressure-regulator settings may not have been optimum, we accept that the natural production of the well was miniscule, and that hopes of significant production must rest on the stimulation. This is scheduled for November 3.

DAILY DRILLING REPORT
ROBERT M. DANN #1 WELL

7-23-80: Moved in IPSCO Dozer. Presently grading location.

7-24-80: Location preparation complete.

7-28-80: Presently rigging up International Petroleum Service Company's rig #2.

7-29-80: Presently waiting on additional 11 3/4" conductor pipe. Spudded at 9 am 7/28/80. Drilled to 60'.

7-30-80: Presently rigging up mud pump to finish drilling conductor hole. Drilled to 80' and still in gravel. Ran 55' of 11 3/4" conductor pipe in hole. Pipe would not drive any further.

7-31-80: Presently drilling at 175' with mud. Drilled out of gravel and into shale at 125'. Could not pull or drive 11 3/4" conductor pipe. Mixed mud to drill surface hole.

8-1-80 : Presently drilling at 419 feet.

8-2-80 : Presently drying up hole 445'. Drilled 445' on mud. Received verbal permission from Oil & Gas Division to set 8 5/8" casing at this point because of hole conditions. Ran 435' of 8 5/8" casing, set at 437'. Cemented with 140 sacks Class A, 3% calcium chloride, 1/2 lb. slocele per sack. Got good cement returns to surface.

8-3-80 : Presently rigging up Birdwell for dry hole log. Driller's TD 1400'. Good show of gas 1070' to 1100'. Drill pipe was wet and muddy indicating water in borehold. Well dusted to TD.

8-4-80 : Presently shut in for pressure build up test. Ran Birdwell dry hole logs, gamma ray, density, caliper, sibilation and differential temperature. Logs indicated good show of gas at 1074' with several other small shows. Open flow test 270 MCFD after well had been opened for 16 hours. Shut in at 1:50 pm August 3, for pressure build up test.

APPENDIX II 5.4

COMPILATION OF MONTHLY REPORTS
ERWIN PROSPECT
DANN #1 WELL
(OCT. 1980-JAN. 1981)

October 31, 1980

Awaiting stimulation scheduled for November 3, 1981.

November 30, 1980

The Dann #1 Well was broken down on 10/20/80. The gas production did not improve after breakdown.

The well was foam fraced on 11/31/80. After eight days of clean up (swabbing), the well continued to make some liquid. The well was shut-in for ten days. Subsequently, clean up (swabbing) indicated that the well continued to make some fluid. Currently the well is shut-in for pressure build test, the start of the Modified Isochronal Test and Buildup Test.

December 31, 1980

The Modified Isochronal Test was performed on the Dann #1 Well on 12/30/80. Results will be available with the January, 1981 Report. The well is presently shut-in for build up test. A gamma ray will be run; however, the spinner and temperature log will not be run.

January 31, 1981

The Build up Test of the Dann No. 1 Well was completed on January 15, 1981. On the same day the Gamma Ray/Tracer Log was run.

The Modified Isochronal Test results require additional analysis and will be forwarded as available.

Corning Natural Gas Company has been approached and has tentatively agreed to take the gas produced from the Dann No. 1 Well over a 60 day test period. This will serve as the ultimate measure of gas productivity (note: there is already in place a gas sales line from the wellhead to Corning Natural's meter — this feeds into a Corning 10 psi gas distribution system).

COMPLETION REPORT
ERWIN PROSPECT
DANN #1 WELL
(NOV. 3, 1980-MAR. 4, 1981)

11-3-80 : Foam frac open hole 1055'-1088'. Used 290,000,300 cu. ft. nitrogen, 5,000 gals. water, 150 sacks 20-40 sand. Average treating pressure 1800 psi. Average rate 2.6 bbls per minute. Open well for blow back at 11:50 am. Blew back through 1/8" choke, recovered some frac sand. Left well open all night.

11-4-80 : Blowing back some water and gas. Rigging up to swab. Swabbed and bailed fluid. Making very little fluid and gas. 5:00 pm left location left well open.

11-5-80 : Bailed and swabbed. Recovered fair amount of fluid.

11-6-80 : Casing pressure 270 psig in 15 hours. Bailed well. Recovered 30' of fluid with each run.

11-7-80 : Casing pressure 250 psig in 15 hours. Ran bailer. Found 15' of fluid in hole. Continuing to run bailer.

11-10-80: Casing pressure 360 psig in 63 hours. Bailed well down by 5:00 pm.

11-11-80: Casing pressure 160 psig in 15 hours. Ran bailer. Got very little fluid. Rigged down and moved to #1 Meter.

11-12-80: Casing pressure 190 psig in 24 hours.

11-14-80: Casing pressure 250 psig in 77 hours.

11-24-80: Casing pressure 395 psig in 13 days. Blew well. Ran swab. Found

300' of fluid. Swabbed well.

11-25-80: Casing pressure 240 psig in 15 hours. Bailed fluid. Still making fluid by end of day.

11-26-80: Bailed well dry. Moved off rig. Shut in for pressure build up.

11-27-80: Casing pressure 165 psig in 15 hours. Found 12' of fluid. Bailed dry. Moved out bailing machine.

12-10-80: Casing pressure 395 psig in 13 days.

12-30-80: Casing pressure 400 psig in 33 days. Dead weight test. Ran modified isochronal flow test. Final flowing pressure 1.8" through 1/2" plate. Installed 1/16" plate for stabilization rate.

12-31-80: Stabilized pressure on 1/16" plate 43 psig. Shut in at 12:15 pm for pressure build up test.

1-2-81 : Casing pressure 280 psig in 46 1/2 hours. Changed chart and left pressure recorder on well.

1-6-81 : Casing pressure 370 psig in 140 1/2 hours.

1-7-81 : Casing pressure 376 psig in 164 1/4 hours.

1-15-81 : Casing pressure 395 psig, dead weight test 15 days. Removed pressure recorder. Blew well down to log. Birdwell ran tracer log. Well made some fluid while coming out of hole with log tool. Shut-in at 12:20 pm. Tracer survey showed a change in scale that is typical when going from casing to open hole. No radiation indicative of frac beads in open hole.

2-23-81 : Installed regulator at wellhead and dessizant gas dryer at meter site

2-24-81 : Completed dryer installation. Casing pressure 420 psig (gauge) 40 days. Turned in line at 10:30 am. 11:15 am checked dew point 20°F up stream from dryer and minus 18°F down stream from dryer. 11:35 am casing pressure 270 psig, and produced 1900 cubic feet. Cut regulator back from 10 psi to 9.5. 4:00 pm found well shut in at meter. Checked drip, no fluid. Total gas produced 5200 cubic feet.

2-25-81 : Information from Ed Lewis; had gas analyzed from 45% nitrogen, 46% methane with BTU of 542.

2-26-81 : Casing pressure 380 psig. Removed regulator spool piece and shut in well at wellhead. Checked gas with explosion meter and found 84% gas. Opened well and blew down to 170 psig. Checked gas and found 68% gas.

3-2-81 : Casing pressure 410 psig. Blew well through 2" opening for 1/2 hour. Installed choke nipple with 3/32" choke at 1:45 pm. Flowing pressure built up to 80 psig in 20 minutes.

3-3-81 : 8:30 am flowing pressure 30 psig through 3/32" choke. Checked gas at noon and found 82% gas. Checked gas at 4:00 pm and found 55% gas. 11:45 am explosive meter showed 82% gas flowing pressure 30 psig. 4:00 pm explosive meter showed 55% gas. Flowing pressure 30 psig. Reportedly making some water. 10:15 pm gas flow is dry. Found a little salt water on gauge clock.

3-4-81 : 7:30 am flowing pressure 30 psig. Trace of salt water at gauge connection.

GAS WELL DELIVERABILITY TEST SUMMARY

APPENDIX II 5.6

GENERAL DATA

WELL NAME No. 1 Dann

LOCATION Steuben Co., NY W

FIELD OR AREA Erwin Prospect

ELEVATION (~~GR~~ DF) 1096' (KB) ft

POOL OR ZONE Devonian Shale

RESERVOIR TEMPERATURE 56 °F

~~XXXXX~~ OPEN HOLE INTERVAL 1055'-1088' ft (KB)

CASING ID 4.052 in TUBING ID ______ in OD 4.50 in PACKER ______ ft (KB)

RESERVOIR GAS PROPERTIES: G 0.60 P_c ______ T_c ______ MOL %: N_2 ______ CO_2 ______ H_2S ______

LICENSEE ______ OPERATOR (Co) Donohue Anstey & Morrill

TYPE OF TEST Modified Isochronal

FINAL DATE OF TEST Jan. 15 19 81

PRODUCTION DATA

RATE NO.	DURATION hours	GAS PRODUCTION Mscfd	CONDENSATE PRODUCTION bbl/d	COND./GAS RATIO bbl/Mscf	GAS-EQUIVALENT OF CONDENSATE Mscfd	TOTAL PRODUCTION-RATE Mscfd	WATER PRODUCTION bbl/d	WATER/GAS RATIO bbl/MMscf
1	1	61	Odor			61	Trace	
2	1	76	0			76	0	
3	1	75	0			75	0	
4	1	90	0			90	0	
EXTENDED RATE	18.33	10	Odor			10	0	

GAS PRODUCED THROUGH: ~~TUBING~~ CASING [X] ANNULUS [ ] TO: PIPE LINE [ ] VENT [ ] FLARE [ ]

FLARE STACK HEIGHT ______ ft DIAMETER ______ in

TOTAL VOLUME OF GAS PRODUCED DURING CLEANUP AND TEST ______ Mscf

EQUIPMENT LIST

- LINE HEATER [ ]
- L.P. SEPARATOR [ ]
- H.P. SEPARATOR [ ]
- CRITICAL FLOW PROVER [X]
- ORIFICE METER [ ]
- LIQUID STORAGE TANK [ ]
- ______ [ ]
- ______ [ ]
- ______ [ ]

REMARKS

STABILIZED SHUT-IN RESERVOIR PRESSURE ($\bar{p}_R$) 425 psia

ABSOLUTE OPEN FLOW POTENTIAL 10 Mscfd

WELLHEAD OPEN FLOW POTENTIAL N/A Mscfd

GAS WELL DELIVERABILITY TEST - FIELD NOTES

WELL NAME No. 1 Dann LOCATION Steuben Co, NY W

FIELD OR AREA Erwin Prospect POOL OR ZONE Devonian Shale

~~PERF~~/OPEN HOLE INTERVAL 1055'-1088' PRODUCING THROUGH: ~~XXXXXXXXXXXXXXXXXXXXXXXX~~ 4 1/2" Casing

WELL BLOWN FOR N.A. minutes SPRAY: WATER/CONDENSATE CLEAR IN ______ minutes

DATE SHUT-IN Nov. 27 19 80 TIME ______ TOTAL SHUT-IN TIME 33 days ~~hours~~

SHUT-IN NO. 1 (INITIAL)

DATE	TIME	CUMULATIVE SHUT-IN TIME days ~~hours~~	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F
11-27-80	4:00P	-		0	
12-30-80	9:05A	33		400	26

REMARKS

All pressures are DWT unless otherwise indicated.

Test run with critical flow prover immediately down stream from wellhead.

FLOW NO. 1

WELL OPENED AT 9:10 AM/~~PM~~ Dec. 30 19 80

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F	METER OR PROVER DATA STATIC PRESSURE psig	DIFFERENTIAL inches H_2O	TEMPERATURE °F
12-30-80	9:10A	-		400	26	400		26
	9:25	0.25		359	30	359		30
	9:40	0.50		342	32	342		32
	9:55	0.75		325	32	325		32
	10:10	1.00		310	34	310		34

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 3/32 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ____ °F LP SEP. ____ psig ____ °F

CONDENSATE PRODUCTION RATE Odor Bbl per hour TOTAL ____ Bbl

WATER PRODUCTION RATE Trace-sl. salty Bbl per hour TOTAL ____ Bbl

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 310 psig

WELL SHUT-IN AT 10:10 AM/~~PM~~ 12-30 19 80 TOTAL FLOW TIME 1 hours

NOTE: FLOWING WELLHEAD PRESSURES AND TEMPERATURES MUST BE UPSTREAM OF ANY CHOKING DEVICE

GAS WELL DELIVERABILITY TEST - FIELD NOTES

SHUT-IN NO. 2 (INTERMEDIATE)

DATE	TIME	CUMULATIVE SHUT-IN TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F
12-30-80	10:10A	-		310	34
	10:25	0.25		334	30
	10:40	0.50		338	28
	10:55	0.75		340	29
	11:10	1.00		342	28

REMARKS

FLOW. NO. 2 WELL OPENED AT 11:10 AM / ~~PM~~ 12-30 19 80

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F	METER OR PROVER DATA STATIC PRESSURE psig	DIFFERENTIAL inches H_2O	TEMPERATURE °F
12-30-80	11:10A	-		342	28	342		28
	11:25	0.25		274	35	274		35
	11:40	0.50		248	36	248		36
	11:55	0.75		224	36	224		36
	2:10P	1.00		202	36	202		36

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 1/8 inches

SEPARATOR CONDITIONS: HP SEP. N.A psig, ____ °F LP SEP. ____ psig, ____ °F

CONDENSATE PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

WATER PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

Little condensation on back of plate.

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 202 psig

WELL SHUT-IN AT 12:10 ~~AM~~ / PM 12-30 19 80 TOTAL FLOW TIME 1 hours

GAS WELL DELIVERABILITY TEST - FIELD NOTES

SHUT-IN NO. 3 (INTERMEDIATE)

DATE	TIME	CUMULATIVE SHUT-IN TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F
12-30-80	12:10 P	-		202	36
	12:25	0.25		240	32
	12:40	0.50		253	30
	12:55	0.75		258	28
	1:10	1.00		261	30

REMARKS

1:53 PM Pressure dropped below 50 psig, the minimum DWT reading.

(1) Pressures interpolated from recording chart and gauge.

FLOW NO. 3 WELL OPENED AT 1:10 ~~AM~~/PM 12-30 19 80

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F	METER OR PROVER DATA STATIC PRESSURE psig	DIFFERENTIAL inches H_2O	TEMPERATURE °F
12-30-80	1:10 P	-		261	30	261		30
	1:25	0.25		92	38	92		38
--	1:40	0.50		62	37	62		37
	1:55	0.75		50	37	(1) 50		37
	2:10	1.00		37	37	(1) 37		37

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 1/4 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ____ °F LP SEP ____ psig, ____ °F

CONDENSATE PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

WATER PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

Little condensation on back of plate.

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 37 psig

WELL SHUT-IN AT 2:10 ~~AM~~/PM 12-30 19 80 TOTAL FLOW TIME 1 hours

GAS WELL DELIVERABILITY TEST - FIELD NOTES

SHUT-IN NO. 4 (INTERMEDIATE)

DATE	TIME	CUMULATIVE SHUT-IN TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F
12-30-80	2:10P	-		(1) 37	37
	2:25	0.25		88	32
	2:40	0.50		109	32
	2:55	0.75		122	34
	3:10	1.00		134	36

REMARKS

FLOW. NO. 4 WELL OPENED AT 3:10 ~~AM~~ / PM 12-30 19 80

DATE	TIME	CUMULATIVE FLOW TIME hours	WELLHEAD PRESSURE psig TUBING	WELLHEAD PRESSURE psig CASING	WELLHEAD TEMPERATURE °F	METER OR PROVER DATA STATIC PRESSURE psig	METER OR PROVER DATA DIFFERENTIAL inches H_2O	METER OR PROVER DATA TEMPERATURE °F
12-30-80	3:10P	-		134	36	134		36
	3:25	0.25		3	40	3		40
	3:40	0.50		2	39	2		39
	3:55	0.75		1	37	1		37
	4:10	1.00		Less than 1	33	Less than 1		33

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 1/2 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ____ °F LP SEP ____ psig, ____ °F

CONDENSATE PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

WATER PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

Little condensation on back of plate.

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING Less than 1 psig

WELL SHUT-IN AT N/A AM/PM ____ 19 ____ TOTAL FLOW TIME 1 hours

GAS WELL DELIVERABILITY TEST – FIELD NOTES

~~CONTINUATION~~ OF FLOW NO. 5 TO STABILIZATION

Date	Time	Cum. Hrs.		Casing psig		Prover psig		Temp.
				Less than 1		Less than 1		33
12-30-80	4:10P	-		37		(1) 37		-
	4:40	0.50		38		(1) 38		30
12-31-80	10:30A	18.33						

METER RUN OR PROVER SIZE 2 inches ORIFICE SIZE 3/32 inches

SEPARATOR CONDITIONS: HP SEP. N.A. psig, ____ °F LP SEP. ____ psig, ____ °F

CONDENSATE PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

WATER PRODUCTION RATE ____ Bbl per hour TOTAL ____ Bbl

Found little fluid in prover. Slight condensate odor, not salty.

FINAL FLOWING WELLHEAD PRESSURE: TUBING ____ CASING 38 psig

WELL SHUT-IN AT 12:15 ~~AM~~/PM 12-31 19 80 TOTAL FLOW TIME 20 hours

FINAL SHUT-IN WELLHEAD PRESSURE: TUBING ____ CASING 395 psig

DURATION OF FINAL SHUT-IN 15 days ~~hours~~ TESTED BY (CO.) Arlington Exploration Company

GAS WELL DELIVERABILITY TEST CALCULATIONS - FLOW RATES

(BASE CONDITIONS = 14.65 psia and 60°F)

CRITICAL FLOW PROVER $q = 10^{-3}\ C\ P\ F_{tf}\ F_g\ F_{pv}$

RATE NO.	PROVER SIZE inches	ORIFICE DIAMETER inches	BASIC ORIFICE COEFFICIENT (C) Mscfd/lb.	STATIC PRESSURE (P) psia	FLOW. TEMP. FACTOR F_{tf}	SPECIFIC GRAVITY FACTOR F_g	SUPERCOMP. FACTOR F_{pv}	FLOW RATE q Mscfd
1	2	3/32	0.1863	325	1.0000	1.0000	1.0000	61
2	2	1/8	0.3499	217	"	"	"	76
3	2	1/4	1.4360	52	"	"	"	75
4	2	1/2	5.6530	16	"	"	"	90
5	2	3/32	0.1863	53	"	"	"	10

GAS WELL DELIVERABILITY TEST CALCULATIONS

(BASE CONDITIONS = 14.65 psia and 60°F)

WELL NAME No. 1 Dann LOCATION Steuben Co., NY W__

POOL OR ZONE Devonian Shale FINAL DATE OF TEST Jan. 15 1981

SIMPLIFIED ANALYSIS

	DURATION hours	SANDFACE PRESSURE psia	CALC.	MEAS.	$p^2 \times 10^{-3}$ psia²	$\Delta p^2 \times 10^{-3}$ psia²	FLOW RATE (q) Mscfd
INITIAL SHUT-IN	33days	425	x		181		
FLOW 1	1	333	x		111	70	61
SHUT-IN	1	366	x		134		
FLOW 2	1	222	x		49	85	76
SHUT-IN	1	283	x		80		
FLOW 3	1	53	x		3	77	75
SHUT-IN	1	153	x		23		
FLOW 4	1	16	x		0.3	23	90
EXTENDED FLOW	18.33	54	x		3	178	10
FINAL SHUT-IN	15days	420	x				

RESULTS

$q = C(\bar{P}_R^2 - P_{wf}^2)^n$

slope n = 0.67*

$\bar{P}_R$ = 425 psia

$C = \dfrac{q}{(\bar{P}_R^2 - P_{wf}^2)^n}$

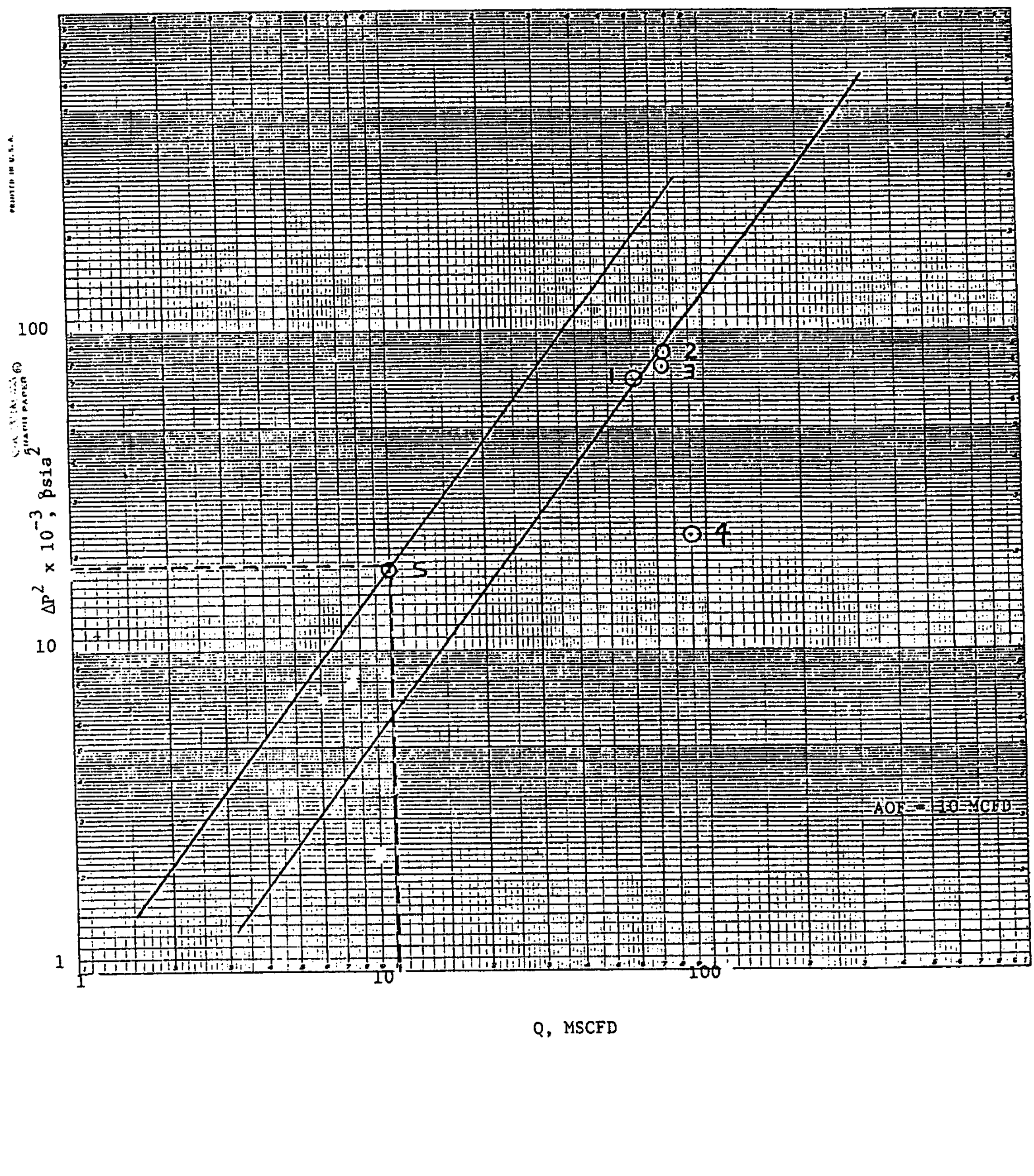
= 0.31 MCFD/psi²

AOF (Mscfd)

= 10 MSCFD

*A slope of 0.67 has been assumed here because the slope generated by plotting the above date points yields N = 0.18 which makes no sense. The slope of 0.67 is equivalent to the slope of the Valley Vista View, Inc. No. 1 well-Marcellus zone.

MODIFIED ISOCHRONAL TEST
DANN NO. 1 WELL
DEVONIAN SHALE
JANUARY 15, 1981

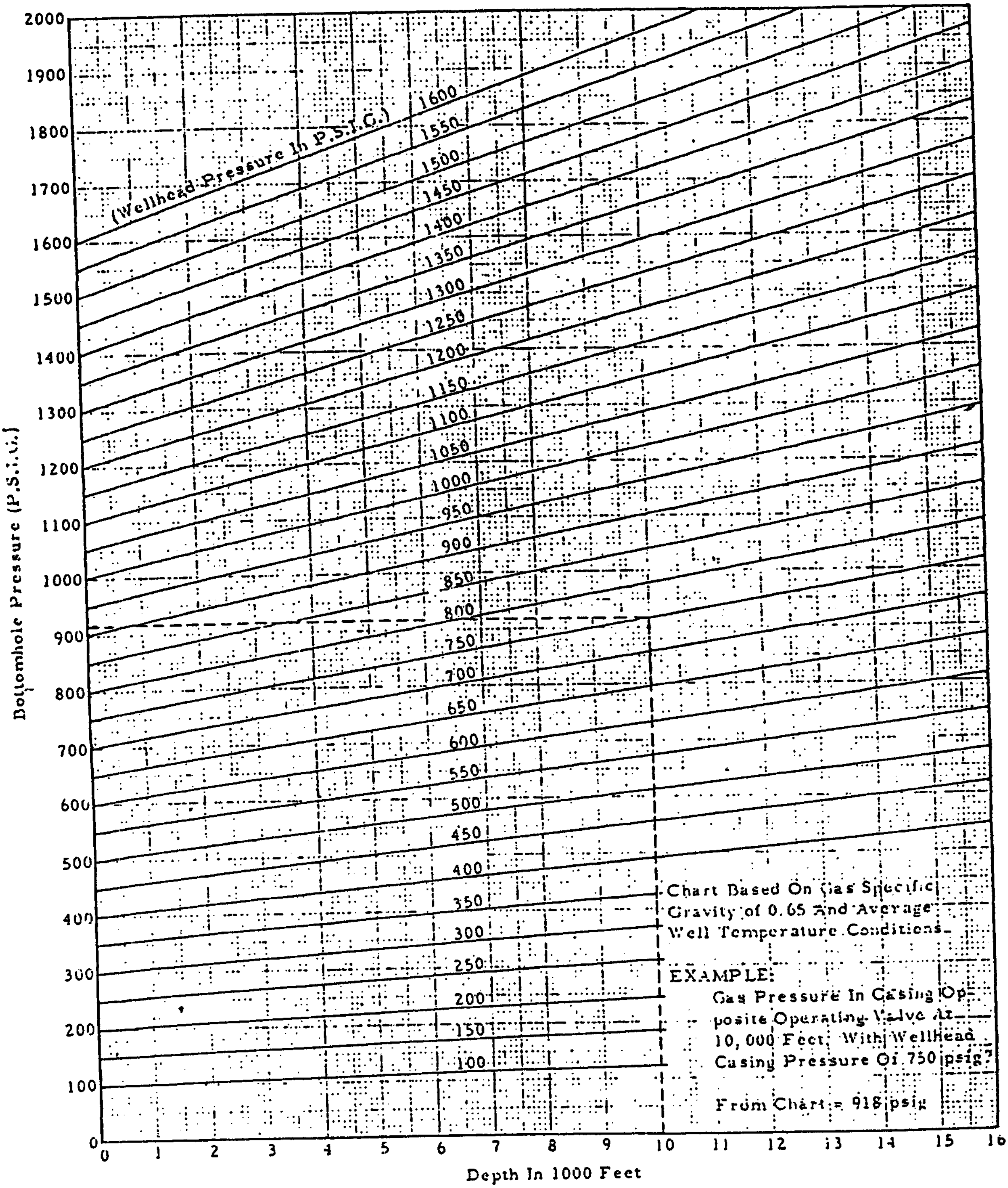


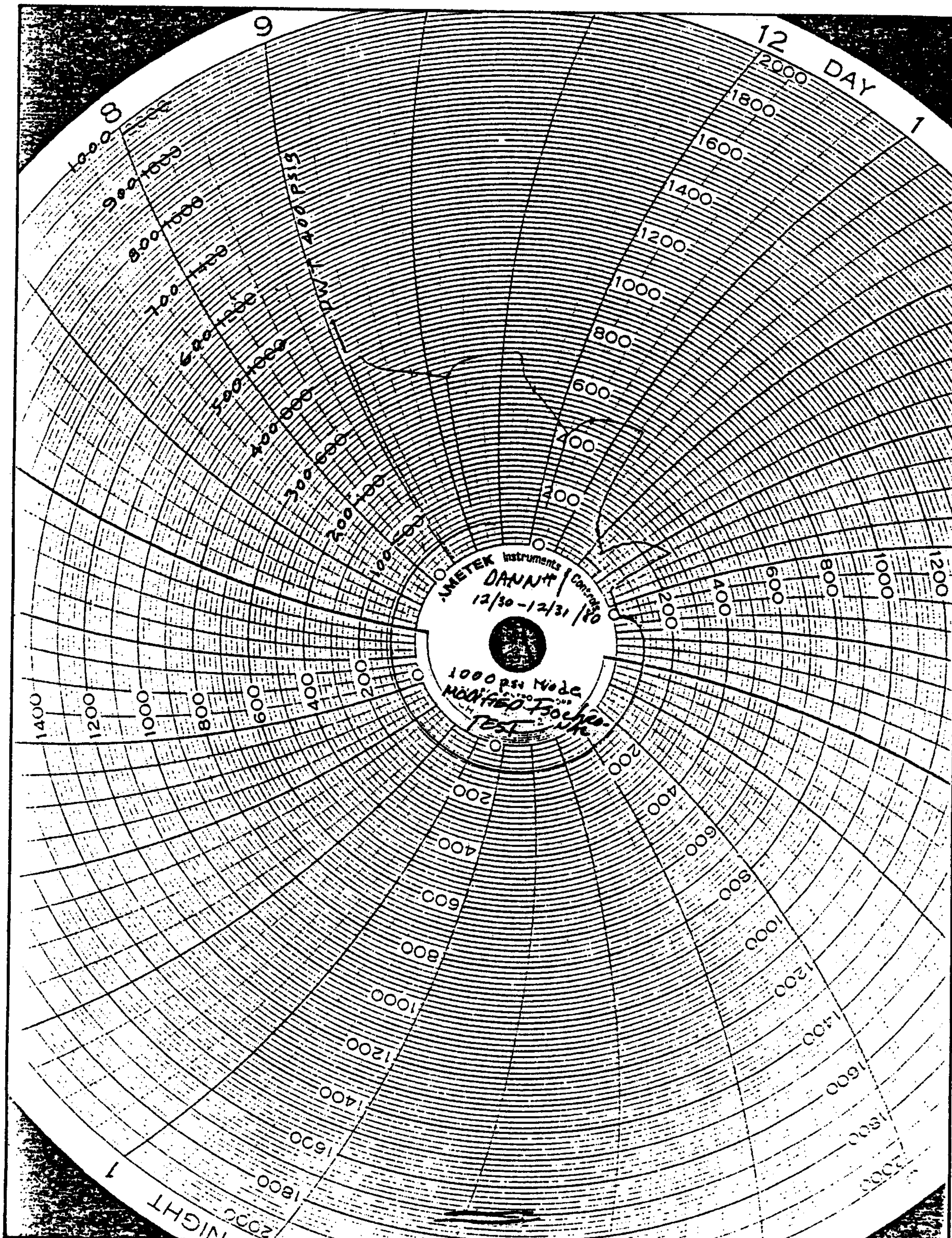
Size of Orifice (inches)	2-Inch Pipe C	Size of Orifice (inches)	4-Inch Pipe C
1/16	0.0846	1/4	1.384
3/32	0.1863	3/8	3.110
1/8	0.3499	1/2	5.564
3/16	0.8035	5/8	8.668
7/32	1.1090	3/4	12.422
1/4	1.4360	7/8	16.893
5/16	2.2080	1	22.007
3/8	3.1420	1 1/8	27.721
7/16	4.5030	1 1/4	34.229
1/2	5.6530	1 3/8	41.210
5/8	8.5500	1 1/2	49.106
3/4	12.4900	1 3/4	67.082
7/8	17.1800	2	88.628
1	22.5800	2 1/4	113.617
1 1/8	28.9200	2 1/2	142.490
1 1/4	36.5100	2 3/4	176.420
1 3/8	44.8600	3	216.790
1 1/2	55.6400		

TABLE 6-1 ORIFICE COEFFICIENTS FOR 2" AND 4" FLOW PROVERS
From Railroad Commission of Texas (1950)

CHART NO. V

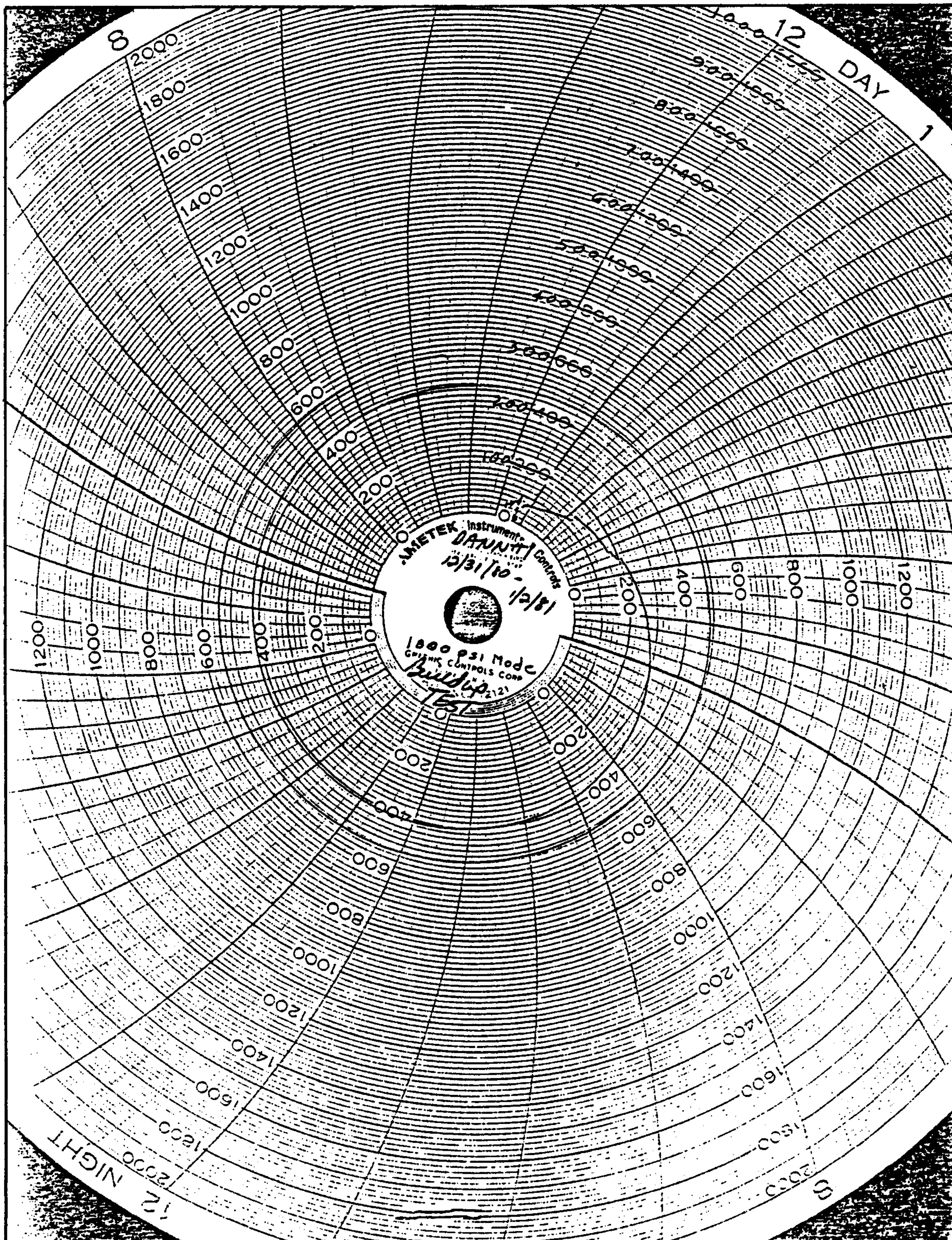
PRESSURE DUE TO GAS COLUMN WEIGHT





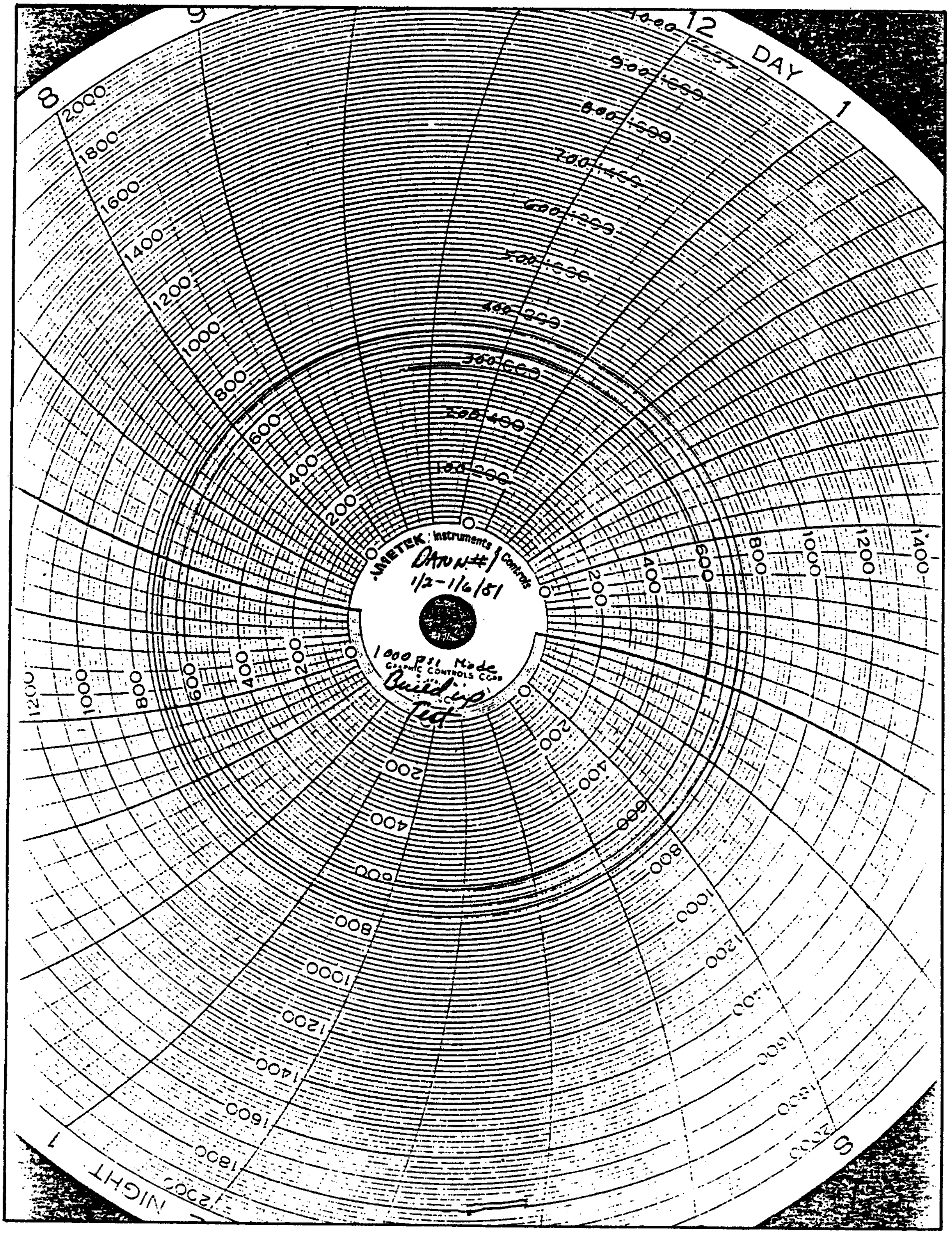
Modified Isochronal Test - Dann #1 Performed 12/30/80-12/31/80

Pressure Recording Chart



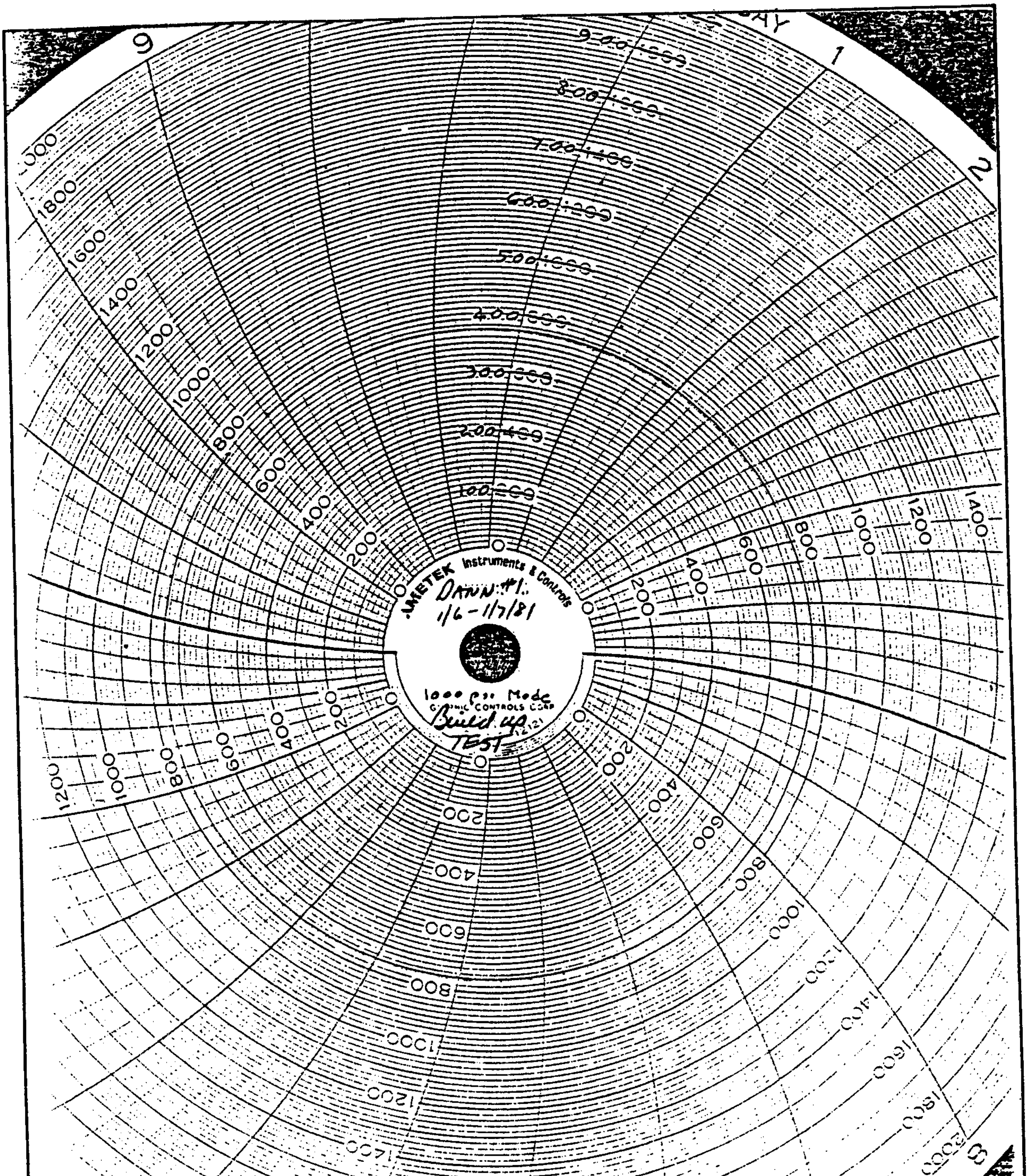
Build-up Test - Dann #1 Performed 12/31/80-1/2/81

Pressure Recording Chart



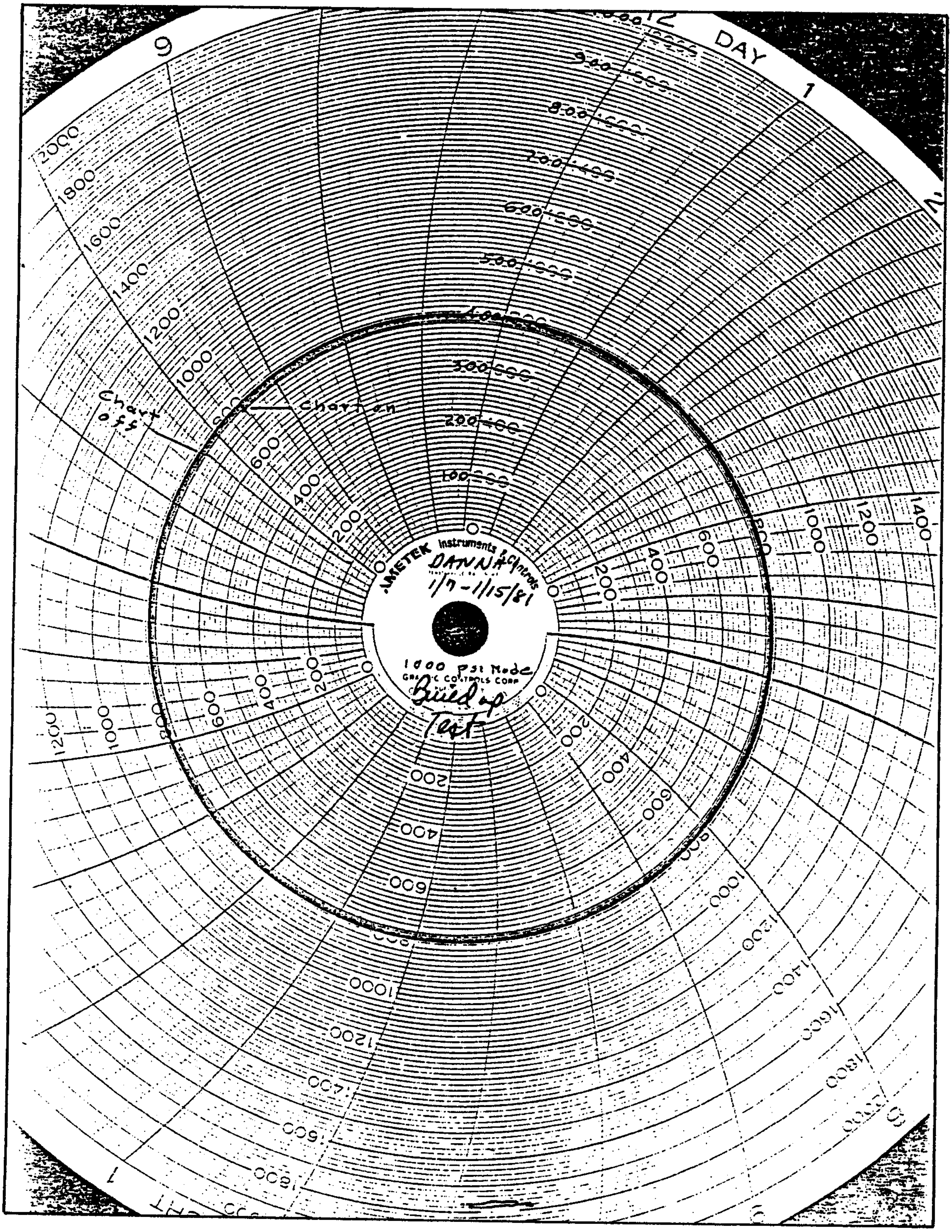
Build-up Test - Dann #1 Performed 1/2/81-1/6/81

Pressure Recording Chart



Build-up Test - Dann #1 Performed 1/6/81-1/7/81

Pressure Recording Chart



Build-up Test - Dann #1 Performed 1/7/81-1/15/81