# RESERVE ESTIMATES FOR EIGHT DEVONIAN SHALE GAS WELLS IN SOUTHERN CENTRAL NEW YORK STATE

Final Report

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Project Manager
Lawrence J. Pakenas

Prepared by

Lynch Consulting Company
Rye, New Hampshire

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## NOTICE



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## LIST OF ABBREVIATIONS

| | |
|---|---|
| MSCF | Thousand Standard Cubic Feet |
| MMSCF | Million Standard Cubic Feet |
| P/Z | Pressure/Gas Deviation Factor |
| Psia | Pounds Per Square Inch Absolute |
| Psig | Pounds Per Square Inch Gauge |
| $Ft^3$ | Feet Cubed |
| Bbls | Barrels |
| Psi/Ft | Pounds Per Square/Feet |
| K-h | Permeability/Thickness |
| Md-Ft | Millidarcies-Feet |
| pws | Static Well Pressure |
| pwf | Flowing Well Pressure |

## SUMMARY


Fourteen shale-gas wells have been drilled in New York State under the United States Department of Energy's Eastern Shale Gas Program since 1979. These wells were completed with funding provided in whole or in part by the New York State Energy Research and Development Authority (NYSERDA). Eight of the NYSERDA-sponsored wells were selected for follow-up evaluation and are the subject of this report.

The eight operating shale-gas wells discussed in this report are as follows:

Valley Vista View, Inc. #1
Houghton College #1
Meter #1
Houghton College #2
St. Bonaventure University #1
Portville Central School #1
Alfred University #1
Allegany County BOCES #1

The results of this study show a wide range in the estimates of available reserves for each of the eight wells. It was not possible to better define the reserves because of the low formation permeability. It is recommended that production be monitored over a long period of time so that the pressure transients which truly express the reserves can be monitored and analyzed.

To the uninformed reader this wide range of reserves may at first be troubling. However, it is important that the uncertainties associated with this resource be properly taken into consideration when developing plans for its exploitation. The results of this study should be considered in this light. More importantly, the recommendations for ongoing monitoring and analysis of pressure and production information deserve careful consideration.

An important factor which will sustain the useful life of the wells is incorporation of improved methods for recovering fluid from the wellbore.

# Section 1
# INTRODUCTION

## OBJECTIVES

The objectives of this project were to estimate the recoverable gas reserves and deliverability of eight shale-gas wells completed in the Marcellus formation in the south central area of New York State, and to evaluate the stimulation procedures used on each of the eight wells.

## SCOPE

A review and analysis of the drilling reports, logs, completion reports, flow test results, and production histories for of each of the wells was undertaken. This review and analysis formed the basis for a series of pressure surveys taken from May through November of 1983 on the eight wells. The tests were designed to yield current formation pressure, ability of gas to flow through the rock per unit of thickness (permeability-thickness product) and wellbore surface damage caused by drilling (skin damage). Estimates of initial gas-in-place and deliverability were made using the pressure and formation parameters.

# Section 2
# FINDINGS

## CONCLUSIONS

The reserve estimates are summarized in Table 2-1. It was assumed when calculating these estimates that it would be possible to produce the wells to atmospheric pressure and that no desorption of gas would take place. These calculations represent a first approximation of the actual reserves that will eventually be produced.

Fluid accumulation, either from injected fracture fluid or natural influx, was apparent in all wells tested. The fluid is mobile which limits the usefulness of surface pressure-measuring instruments and impairs the gas deliverability of the wells. Of the eight wells tested, only three were amenable to conventional analysis. The results of the tests are given in Table 2-2.

Stimulation treatments appear to be adequate; however, a better method of removing fracture fluid must be found. Recommendations include tubing siphon string and downhole pump.

## RECOMMENDATIONS

Two wells are recommended for further data gathering, analysis, and completion work. The additional work at these wells should provide valuable insight into the potential worth of pursuing the same kind of treatment for the remainder of the wells.

Houghton College No. 1 and Allegany County BOCES No. 1 both showed high estimates of initial gas-in-place, 31.2 MMSCF and 78.8 MMSCF, respectively. Houghton College No. 1 has produced the largest cumulative volume of gas (22.5 MMSCF) and is currently at a low pressure (371 psia). Houghton College No. 1 is ideal for examining the impact of low pressure desorption of gas on future production. BOCES No. 1 has the highest remaining reserves (76.4 MMSCF) and a low sustained deliverability which makes it ideal to examine the potential benefit of removing the remaining fracturing fluid.

## Remedial Completion Work

Both wells should be equipped with a means of removing wellbore fluid accumulations. In the case of Houghton No. 1, a siphon tube has proved inadequate; thus an annular, fluid-level-controlled, down-hole pump is recommended. BOCES No. 1 could initially be equipped with a siphon tube since this well has sufficient energy to expel some fluid from the 4 1/2-inch casing. It is probable that the siphon string will need to be replaced by a down-hole pump at a later time, when the formation energy is depleted.

## Additional Data Gathering

Regular shut-in pressure surveys must be obtained at least once a year or at cumulative production increments of 500 MSCF if the shape of the (P/Z) versus cumulative production curves is to be defined. Surface pressure surveys should be supplemented with down-hole gradient surveys or echometer readings to evaluate true formation pressure.

In future stimulation treatments, it is recommended that the effects of a methanol additive to the fracture fluid be investigated. This type of treatment has been used in organic shales in Quebec, Canada with reported fluid recoveries of up to 90%.

The source of communication between the 4 1/2-inch casing and the 8 5/8-inch surface pipe at the Houghton College No. 2 well should be investigated and the problem rectified.

To gain some insight into the potential value of desorption, the Langmuir isotherm should be experimentally developed using fresh core samples. That is, to adequately investigate the phenomenon of gas desorption from the formation, it is necessary to measure the actual data rather than rely on general correlations.

Table 2-1
Reserve Estimates[a/]
(MMSCF)

| Well Name | Initial Gas In Place | | Cumulative Production | Remaining Reserve | |
|---|---|---|---|---|---|
| | Low | High | | Low | High |
| Valley Vista View | 3.32 | 5.32 | 2.15 | 1.17 | 3.17 |
| Houghton #1 | 27.50 | 31.40 | 22.47 | 5.03 | 8.93 |
| Meter #1 | 7.25 | 9.90 | 3.12 | 4.13 | 6.78 |
| Houghton #2 | 1.00 | 1.00 | 0.63 | 0.37 | 0.37 |
| St. Bonaventure | 4.20 | 6.20 | 0.72 | 3.48 | 5.48 |
| Portville | 1.95 | 2.50 | 0.93 | 1.02 | 1.57 |
| Alfred | 4.65 | 10.45 | 1.23 | 3.42 | 9.22 |
| BOCES | 14.80 | 78.80 | 2.44 | 12.36 | 76.36 |

a/ Assumes no desorption and an abandonment pressure of 15 psia

Table 2-2

FRACTURE TREATMENTS

| Well Name | Date | Total Sand Wt. (lbs) | Volume ($ft^3$) | Voidage ($ft^3$) | Casing Volume (Dry) ($ft^3$) | Total Fluid Inj (Bbls) | Total b/ Fluid Recovered (Bbls) | Fluid Remaining (Bbls) |
|---|---|---|---|---|---|---|---|---|
| Valley Vista View | Dec 81 | 80,000 | 702 | 155 | 349 | 312 | NA | |
| Houghton #1 | Oct 79 | 50,000 | 449 | 99 | 208 | 333 | NA | |
| Meter #1 | Nov 80 | 76,000 | 683 | 151 | 1445 | 289 | NA | |
| Houghton #2 | Aug 81 | 60,000 | 539 | 119 | 221 | 333* | 168 | 165 |
| St. Bonaventure | Aug 81 | 60,000 | 539 | 119 | 330 | 333* | 164 | 169 |
| Portville | July 81 | 60,000 | 539 | 119 | 379 | 333* | 164 | 169 |
| Alfred | July 81 | 60,000 | 539 | 119 | 357 | 333* | 146 | 187 |
| BOCES | July 81 | 60,000 | 539 | 119 | 299 | 333* | 159 | 174 |

b/ recovered during initial clean up

*includes 37 bbls hydrofluoric acid

With the exception of the Meter #1 well, all wells were completed in the Marcellus shale unit of the Hamilton group, middle Devonian system. The Meter #1 was perforated over a total interval of 286 feet which spanned the Marcellus as well as other shales in the Hamilton group. The Marcellus shale in the eight wells ranges in depth from about 1600 feet to 4000 feet and exhibits a thickness of 28 feet to 114 feet.

A blanket of glacial till, which ranges in thickness from a few feet to a few tens of feet in high topographic areas to several hundred feet in major river valleys, covers most of the area.

The bedrock layers of Paleozoic Age dip southerly into the Appalachian Basin at a rather gentle rate. Numerous localized faults and anticline-syncline systems have contributed to the trapping mechanism for hydrocarbon deposits. (See Figure 3-2 for stratigraphic section.)[1/]

When natural gas became scarce in the 1970s, there came a renewed interest in natural gas production from the Eastern Devonian black shales. Drillers had often encountered shows in these zones while drilling to older horizons, and it was thought that the Devonian shales might have some potential as a commercial gas-producing zone.

It is now realized that, while the black shales contain large quantities of gas, production is controlled by naturally fractured zones; stimulation with today's technology has only marginally affected production at some wells.

The purpose of the following discussion is to relate each well to its geological setting as it applies to the all-important fracture system which seems to control the production and reserves represented by each well.

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[1/]Arthur M. VanTyne and Brayton P. Foster, "Inventory and Analysis of the Oil & Gas Resources of Allegany & Cattaraugus Counties, New York", Part I & II, 1979.

## Section 3
## GEOLOGIC OVERVIEW

### LOCATION OF WELLS

The eight wells in question were drilled within a thirty-five mile radius in portions of five counties in southwestern New York. (See Figure 3-1.)

- Valley Vista View #1 - South Central Steuben County
- Houghton College #1 - Northwestern Allegany County
- Meter #1 - Southern Livingston County
- Houghton College #2 - Northwestern Allegany County
- St. Bonaventure University #1 - Southeastern Cattaraugus County
- Portville School #1 - Southeastern Cattaraugus County
- Alfred University #1 - Eastern Allegany County
- BOCES #1 - Central Allegany County

### Discussion

Calculating gas-in-place, and hence reserves, in fractured shales is a complex problem involving free gas, trapped gas and adsorbed gas. The free gas is contained in the wellbore and fracture system, trapped gas in the micropores of the matrix and adsorbed gas on the surface of the shale itself.

Conventional reserve analysis compares the physical size of the reservoir with the volume that can be inferred from pressure and production history. The Marcellus shale is widespread throughout the region, but its extent has little influence on the gas-in-place or reserves that can be attributed to a specific well. The important feature that makes for a good well is the extent of natural fracturing in the vicinity of the wellbore and the ability of the induced fractures to make contact with the natural fracture system. The primary objectives of this study, namely gas reserve and deliverability prediction, meant that the emphasis was placed on reviewing pressure-production performance. Less emphasis was placed on detailed geologic and petrophysical analyses. Petrophysical analysis was used only to validate the net pay thickness for use in permeability and areal distribution calculations.

Valley Vista View #1 - Rathbone Prospect

It seems the exploration rationale presented in Appendix II 2.1 of "Shale Gas in the Southern Central Area of New York State," Volume II, NYSERDA, 1981[2] was very well thought out, and the drilling of the Valley Vista View #1 well did not provide any data to significantly change the rationale. See Figure 3-3 for a Structure Map.

The following comments are offered for consideration:

In paragraph four,(Appendix II, 2.1 - NYSERDA, 1981), a seismic line that runs generally N-S about two miles west of the old field is mentioned. Perhaps this data can be reinterpreted to improve the interpretation of the flex. The surface elevations could be resurveyed and the proper static corrections applied.

Paragraph five mentions a seismic line NE of the field which was not available in 1980. Perhaps this information is available now.

Paragraph eight states the reason for the location of VVV #1. Future locations in the fairway of interest may become available. However, since the wellbore of VVV #1 is interpreted to have penetrated a reverse fault, apparently causing thickening and fracturing of the Marcellus shale, it might be worthwhile to attempt to stay on trend with this fault for future locations.

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2/Donohue, Anstey & Morrill, "Shale Gas in the Southern Central Area of New York State," Vol. II, April, 1981, New York State Energy Research & Development Authority & U.S. Dept. of Energy, Morgantown Energy Technology Center, Boston, MA.

Houghton College #1 & #2

The wells were drilled about one mile apart, and both penetrated the Tully limestone at the same elevation (-563 feet). The Tully limestone lies a few hundred feet above the Marcellus shale and is commonly used as a structural marker bed in the southern tier of New York State. The fact that both wells penetrated the Tully at the same elevation is not anomalous since the Houghton College #2 well was drilled just slightly south of west of the Houghton College #1. The dip of the Tully in this area of Allegany County is generally south at about 50-100 feet per mile. Both wells are located about two miles south of a faulted area; the two interpreted faults trend ENE and are up-thrown to the north. Both wells seem to be near a change in slope of regional dip; however, subsurface data are sparse in this particular area. See Figure 3-4 for a Structure Map.

There is no significant oil or gas production within a distance of five miles according to the map by Donohue, Anstey & Morrill.[3/]

Meter #1 - Dansville Prospect

According to a map on top of the Tully limestone (by Donohue, Anstey & Morrill) the old Dansville Field seems to lie in a subtle anticline-syncline system which trends SE at right angles to the regional dip. This condition may be responsible for the fracture system in the shale which enhanced production from this field. This flexing may be more intense than shown but cannot be determined from the sparse well data. See Figure 3-5 for a Structure Map.

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[3/] Donohue, Anstey & Morrill, op.cit.

St. Bonaventure University #1

This well penetrated the Tully limestone at an elevation of -1785 feet which fits the structure map almost perfectly.[4/] The well was drilled approximately one mile SE of an interpreted fault which trends NE-SW and is up-thrown to the north. The University #1 apparently did not penetrate an extensive fracture system since it is a rather poor producing shale well. See Figure 3-6 for a Structure Map.

The nearest oil production is immediately to the northwest in the shallow Devonian oil field (Bradford) while the nearest gas production is 4 1/2 miles NNE in the McClure Hollow Field which produces from a lower horizon.

Portville School #1

This well penetrated the Tully limestone at an elevation of -2229 feet which is about 180 feet lower than one would have predicted from the regional structure map.[4/] This well was drilled about one mile NW of an interpreted fault trending NE-SW with the northwest side up-thrown. With the information from the Portville School #1 taken into account, one would reinterpret the fault to lie on the northwest side of this well. Even then, the top of the Tully would be low since there is only about 50 feet of displacement across the fault as interpreted on the structure map. This would lead one to believe the well lies in a graben; however, the subsurface control is very poor in this area. The well apparently did not penetrate an extensive fracture system since it is a rather poor producing shale well. See Figure 3-6 for a Structure Map.

The nearest gas production is from the Ceres field, the edge of which is located about 1 1/2 miles east of the Portville School #1 well. This field, as well as the Portville South pools (approximately 1 1/2 miles SW) produces or did produce gas from the upper Devonian.

[4/]Arthur M. VanTyne and Brayton P. Foster, op.cit.

Alfred University #1

The Alfred University #1 well penetrated the Tully limestone at an elevation of -1413 feet. The Tully was penetrated 7 feet higher than in the Burdick #1 well (dry hole) located 7500 feet almost due east. This is slightly anomalous since the regional dip is SSE at the rate of 50-75 feet per mile. According to the Donohue, Anstey & Morrill map, the top of the Tully is about 18 feet low.[5/] However, there is such sparse subsurface data in this area that it is difficult to determine anomalous conditions. The rate of dip does seem to change in the area of the Alfred well but is probably too subtle to cause fracturing of the shale. See Figure 3-7 for a Structure Map.

There is no significant oil or gas production within five miles of the Alfred well while there appears to be complex faulting associated with the fields to the south and southeast. These fields produced from the upper Devonian sandstone. There are also faults to the northwest and west which seem to be associated with gas wells. All faults in the area are apparently up-thrown to the north.

From the above discussion, it seems coincidental that the Alfred well penetrated sufficient fractures in the shale to allow significant quantities of gas to enter the wellbore.

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[5/] Donohue, Anstey & Morrill, op.cit.

Allegany County BOCES #1

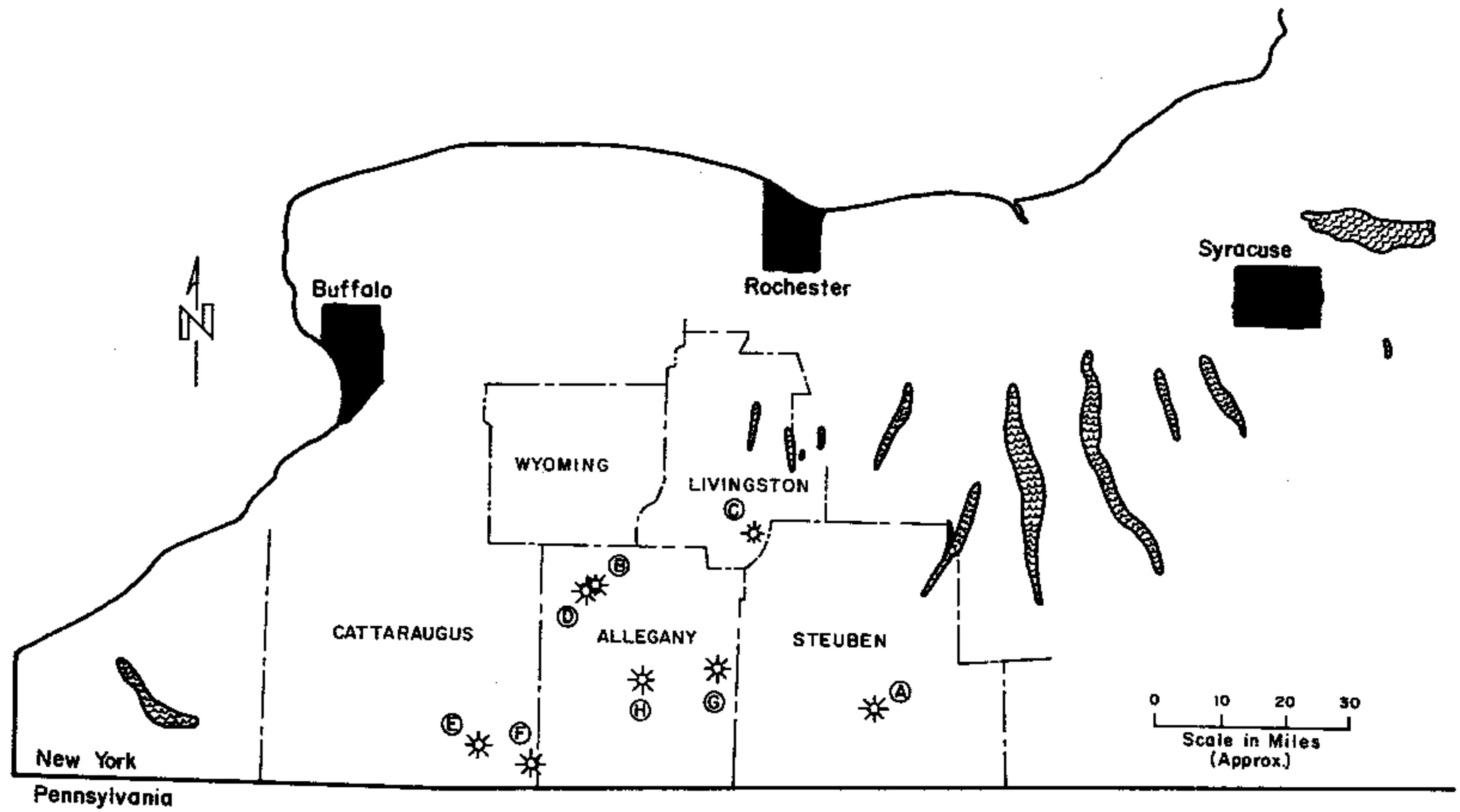
This well penetrated the Tully limestone at an elevation of -1369 feet, which is about 120 feet lower than one would predict from the regional structure map.[6] It is located rather remotely from other wells which is probably why the regional map did not predict the top of the Tully more accurately. The subtle syncline located between the two faults on the map would simply become more intense if one adjusted the contours to accommodate the top of the Tully in the BOCES #1.

Since this well exhibited rather high reserve estimates from the testing procedure, the wellbore must be in contact with a fairly extensive fracture system. The more intense syncline system could have caused flexing of the shale beds which resulted in the fracture system that apparently exists.

The nearest gas production is about five miles southeast in the Gordon Brook field. Here, gas is (or was) produced from a lower horizon. No other gas fields are located in the area; three upper Devonian oil fields are located within five miles to the southwest, south and southeast (Corbin Hill, East Hill and Scio).

[6] Arthur M. VanTyne and Brayton P. Foster, op. cit.

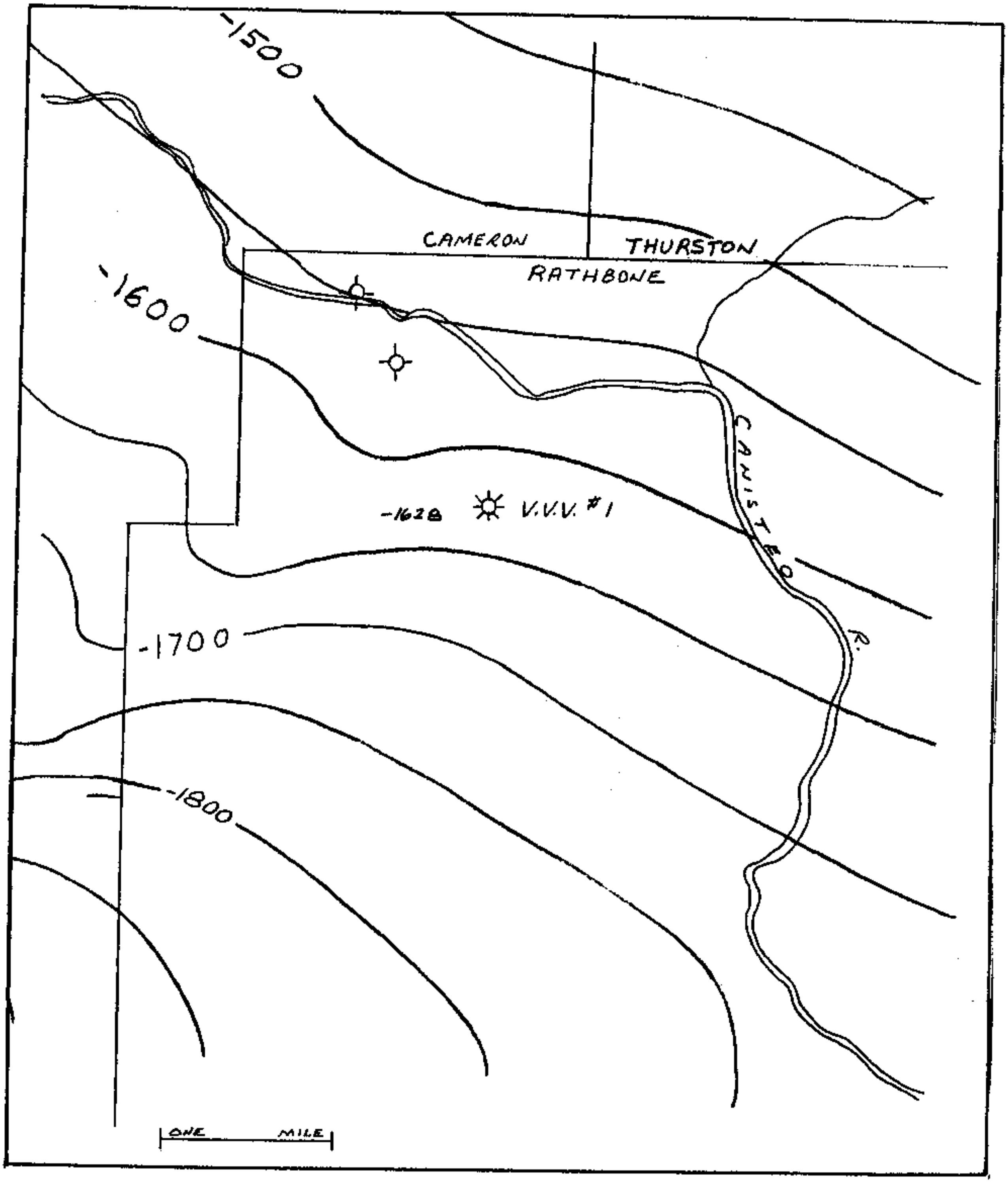
# WESTERN NEW YORK




LEGEND:

- Ⓐ Valley Vista View # 1
- Ⓑ Houghton College # 1
- Ⓒ Meter # 1
- Ⓓ Houghton College # 2
- Ⓔ St. Bonaventure U # 1
- Ⓕ Portville School # 1
- Ⓖ Alfred U. # 1
- Ⓗ Boces # 1

**DEVONIAN SHALE WELLS**
**Fig. 3-1**




**VALLEY VISTA VIEW - 1**

**CONTOURS ON TOP OF TULLY LIMESTONE**

**FROM DONOHUE , ANSTEY & MORRILL (1981)**

**Fig. 3-3**

| PERIOD | | GROUP | UNIT | THICKNESS | PRODUCTION |
|---|---|---|---|---|---|
| Penn. | | POTTSVILLE | OLEAN Ss,Cgl | 75-100' | |
| Miss. | | POCONO | KNAPP Ss,Cgl | 60-100' | |
| DEVONIAN | UPPER | CONEWANGO | Sh,Ss,Cgl | 700' | |
| | | CONNEAUT | CHADAKOIN Sh,Ss | 700' | |
| | | CANADAWAY | UNDIFF. † Sh,Ss | 1100-1400' | Oil,Gas |
| | | | PERRYSBURG# Sh,Ss | | Oil,Gas |
| | | WEST FALLS | JAVA<br>NUNDA Sh,Ss<br>RHINESTREET | 375-1250' | Oil,Gas |
| | | SONYEA | MIDDLESEX Sh | 0-400' | Gas |
| | | GENESEE | Sh | 0-450' | |
| | ? | | TULLY Ls | 0-50' | Gas |
| | MIDDLE | HAMILTON | MOSCOW Sh<br>LUDLOWVILLE Sh<br>SKANEATELES Sh<br>MARCELLUS Sh | 200-600' | Gas |
| | | | ONONDAGA Ls | 30-235' | Gas,Oil |
| | LOWER | TRISTATES | ORISKANY Ss | 0-40' | Gas |
| | | HELDERBERG | MANLIUS Ls<br>RONDOUT Dol | 0-10' | |
| SILURIAN | UPPER | | AKRON Dol | 0-15' | Gas |
| | | SALINA | CAMILLUS Sh,Gyp.<br>SYRACUSE Dol,Sh,Salt<br>VERNON Sh,Salt | 450-1650' | |
| | | LOCKPORT | LOCKPORT Dol | 150-250' | Gas |
| | | CLINTON | ROCHESTER Sh<br>IRONDEQUOIT Ls | 125' | |
| | LOWER | | SODUS Sh<br>REYNALES Ls | 75' | |
| | | | THOROLD Ss | 2-8' | |
| | | MEDINA | GRIMSBY Sh,Ss<br>WHIRLPOOL Ss | 75-140'<br>0-25' | Gas<br>Gas |
| ORDOVICIAN | UPPER | | QUEENSTON Sh<br>OSWEGO Ss | 1100-1500' | Gas |
| | | | LORRAINE Sh<br>UTICA Sh | 900-1000' | |
| | MIDDLE | TRENTON-BLACK RIVER | TRENTON Ls<br>BLACK RIVER Ls | 425-625'<br>225-550' | Gas |
| | LOWER | BEEKMAN-TOWN | TRIBES HILL-CHUCTANUNDA Ls | 0-550' | |
| CAMBRIAN | UPPER | | LITTLE FALLS Dol | 0-350' | |
| | | | GALWAY (THERESA) Dol,Ss | 575-1350' | Gas |
| | | | POTSDAM Ss,Dol | 75-500' | Gas |
| PRECAMBRIAN | | | GNEISS, MARBLE, QUARTZITE, etc. | | |

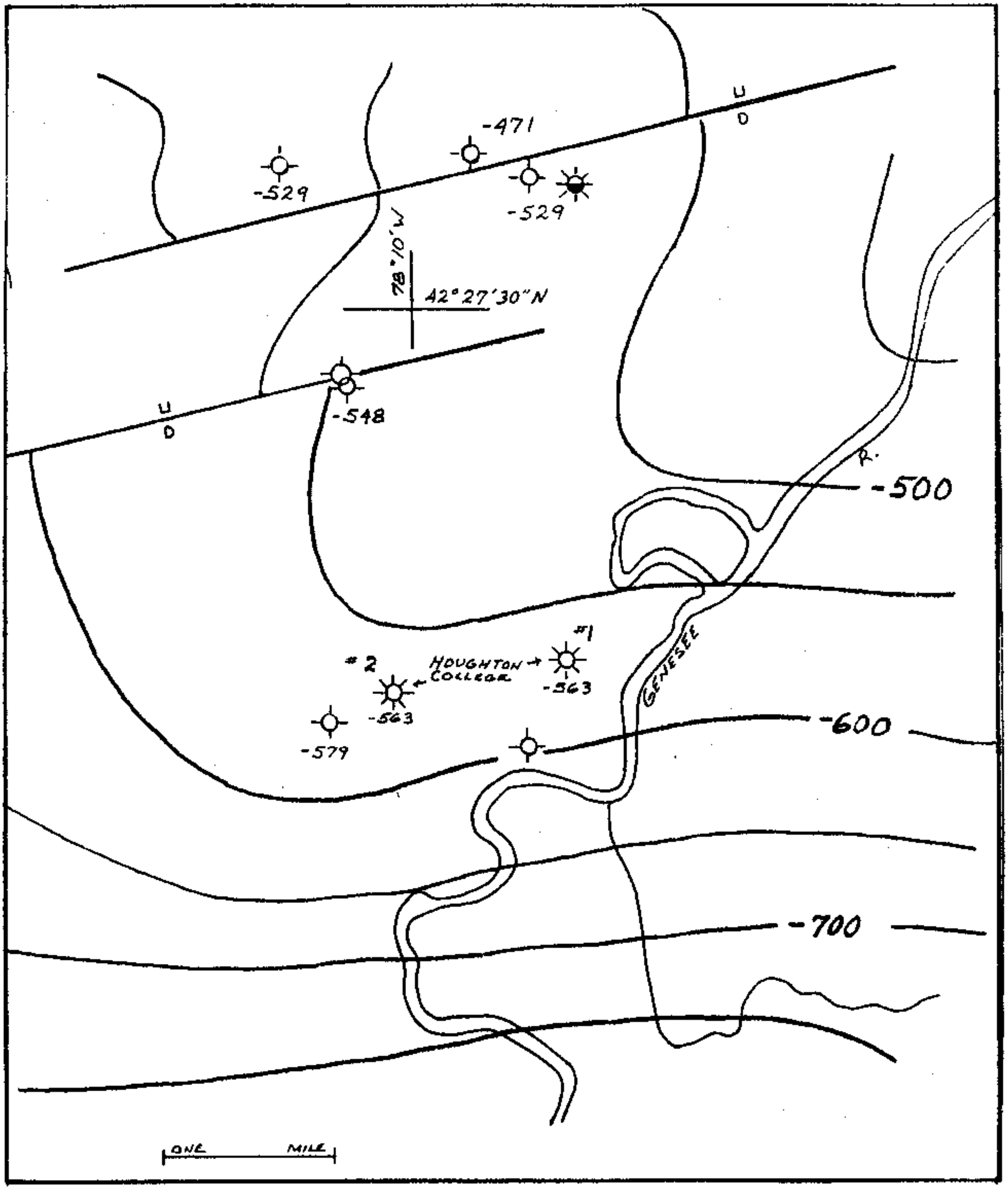
FROM VAN TYNE & FOSTER(1979)

† INCLUDES GLADE, BRADFORD 1st, CHIPMUNK BRADFORD 2nd, HARRISBURG RUN, SCIO, PENNY, & RICHBURG

# INCLUDES BRADFORD 3rd, HUMPHREY, CLARKSVILLE, WAUGH & PORTER, & FULMER VALLEY

**COMPOSITE PALEOZOIC STRATIGRAPHIC SECTION FOR SOUTHWESTERN NEW YORK**

**Fig. 3-2**

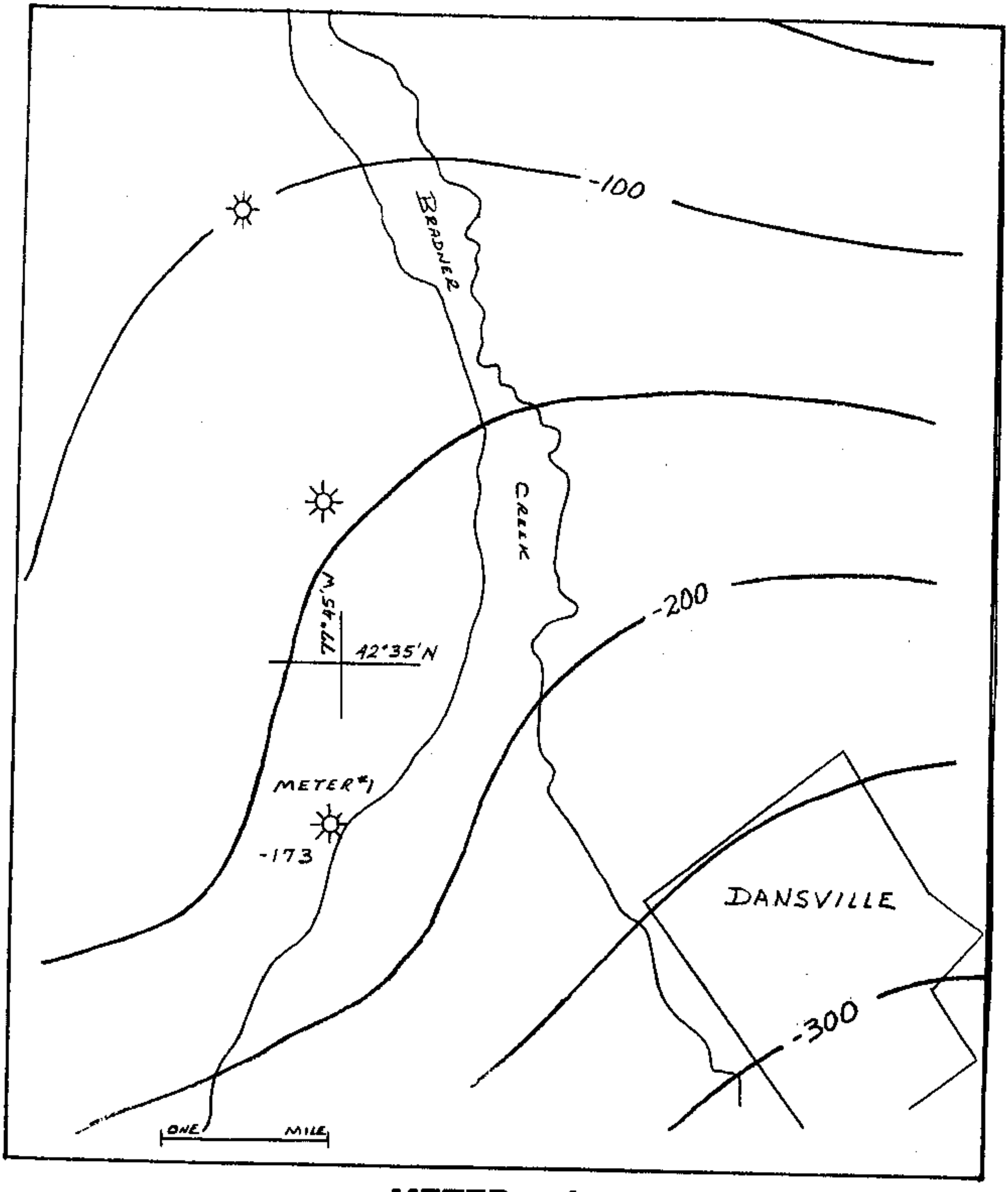



**HOUGHTON COLLEGE - 1 & 2**

**CONTOURS ON TOP OF TULLY LIMESTONE**

**FROM DONOHUE ,ANSTEY & MORRILL (1981)**

**Fig. 3-4**

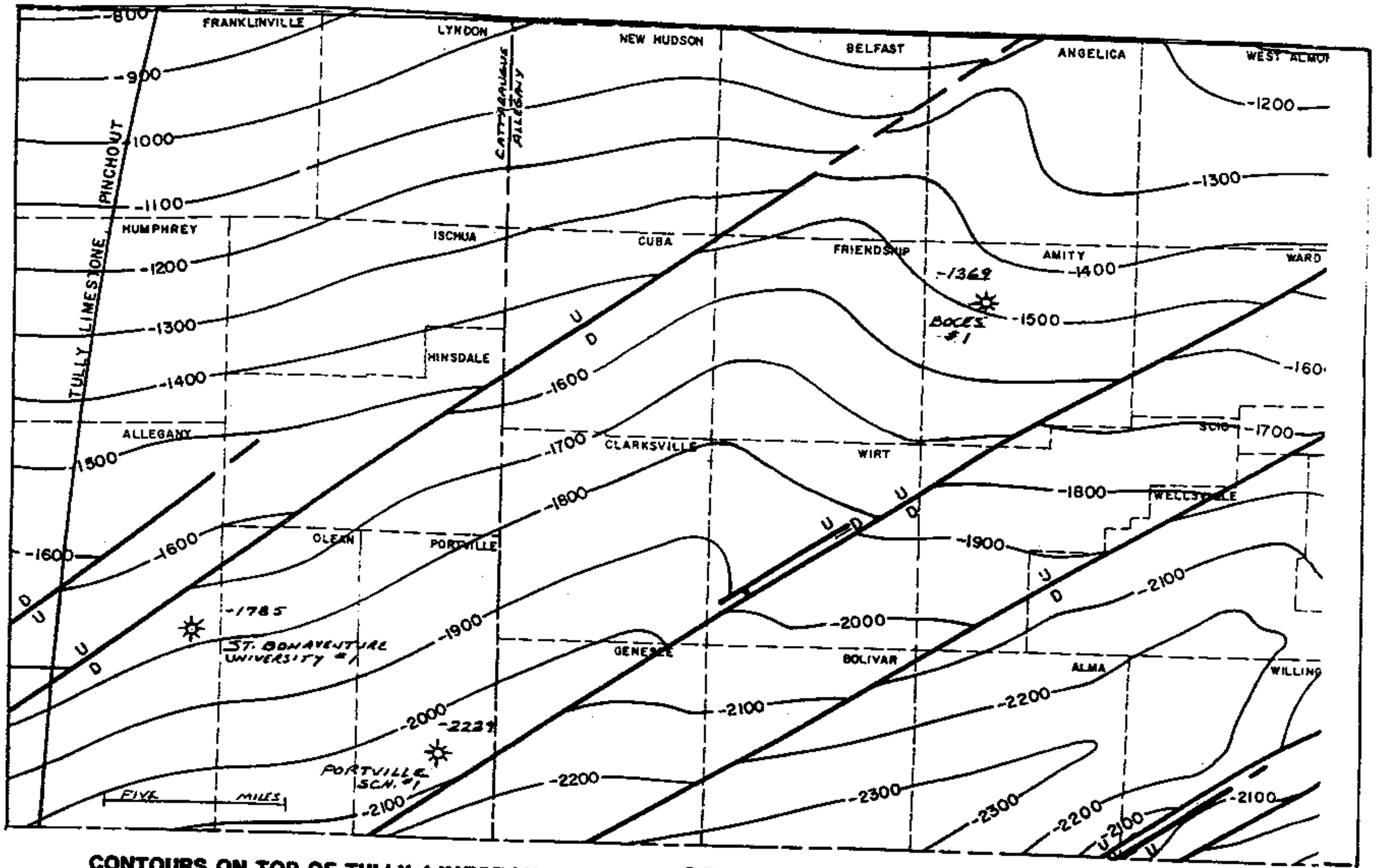



# METER - 1

**CONTOURS ON TOP OF TULLY LIMESTONE**

**FROM DONOHUE , ANSTEY & MORRILL (1981)**

**Fig. 3-5**

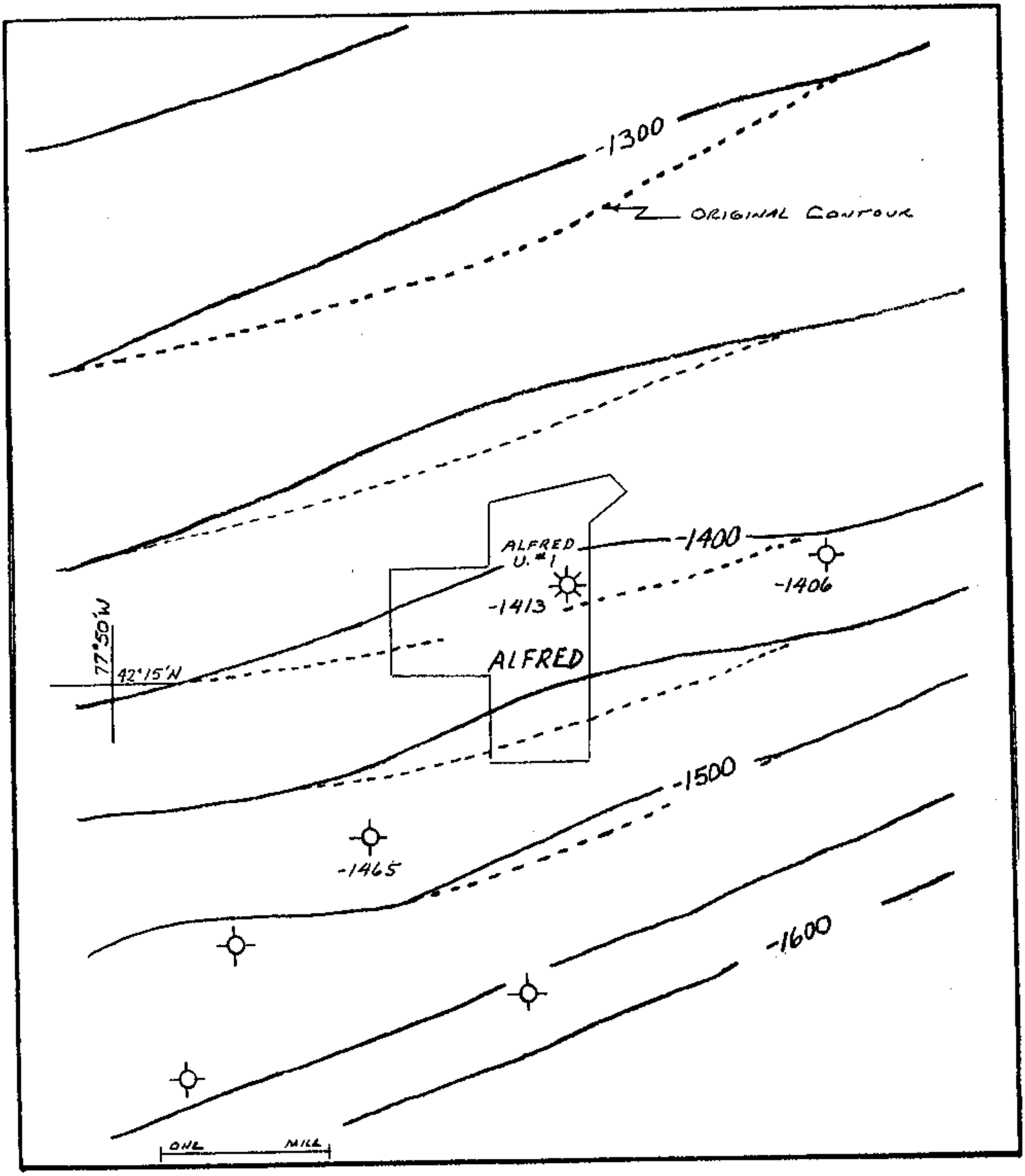



CONTOURS ON TOP OF TULLY LIMESTONE

FROM VAN TYNE & FOSTER (1979)

**ST. BONAVENTURE U. - 1**
**PORTVILLE SCH. - 1**
**BOCES - 1**

Fig. 3-6




# ALFRED U. - 1

**CONTOURS ON TOP OF TULLY LIMESTONE**

**FROM DONOHUE , ANSTEY & MORRILL (1981)**

**Fig. 3-7**

# Section 4
# ENGINEERING ANALYSIS

## PRESSURE/PRODUCTION PERFORMANCE

Initial pressure surveys were available for all wells. The surveys had been run following stimulation, subsequent to clean-up and shut-in periods. Because of the injectants used during the fracture treatments and the varying clean-up and shut-in periods, the initial pressure measurements obtained after drilling are not significant indicators of well performance. Figure 4-1 shows a plot of the final shut-in pressures after drilling (corrected to the mid-point of perforations assuming a dry gas column) plotted against measured depth to determine a pressure gradient. The pressure gradient correlation is fairly good, with the line of best fit having a slope of .51 psi/feet. A second gradient plot of initial pressure versus subsea depth was prepared to confirm the first gradient measurement. In this case, however, the scatter was so severe that no useful correlation could be found. It is probable that the true gradient was about 0.46 psi/feet with the Meter #1 and the St. Bonaventure wells falling close to this value. The other six wells, with the exception of Valley Vista View, are less than 250 psi higher than the .46 psi/feet gradient.

A review of production records shows that all of the eight wells are used to deliver "make up" gas as required for intermittent heat loads. As such, the current production history reflects the consumer need and reveals no quantitative information concerning the size of the gas reserve or its deliverability.

## PRESSURE TESTING

Pressure surveys have been run on several of the wells during the course of their producing lives. These surveys were modified isochronal tests which consisted of flowing and shut-in periods of one hour duration each. During each cycle of a test, a well was allowed to produce against a fixed choke, then shut-in. The complete modified isochronal test included four flowing-shut-in cycles with progressively larger chokes followed by an extended 36-48-hour flowing period.

From this data it is usually possible to construct a backpressure/deliverability curve for a well which relates the productivity/deliverability of the well for a given reservoir pressure. During the short flowing period, the predominant source of gas is from wellbore decompression. The formation reacts more slowly; consequently, isochronal testing is of limited value for determining gas reserves.

A testing rationale was developed for this project using the results of a pressure survey conducted for the Valley Vista View well. The analysis and recommended testing procedures are described in detail in Appendix B. The testing procedure used reflects a compromise between the ideal case of down-hole pressure recorders and constant flow control equipment, and the actual equipment available for this project.

The testing procedure consisted of flowing the wells at two increasing rates via a critical flow prover. The flow testing was followed by an extended pressure build-up period. The duration of the flowing periods was designed to ensure that the formation, and not the wellbore, was the predominant gas source. The two rates were also used to examine the skin term and hence evaluate the effectiveness of the fracture treatments.

The details of the individual well tests are included in Appendix A. The analysis consisted of calculating:

- production rate during the flowing period,
- the inferred permeability thickness product from the drawdown data,
- the duration of wellbore storage from build-up data,
- the inferred permeability thickness product from the build-up data,
- the skin term inferred from the build-up data.

The analysis was only partially successful. There are two probable explanations for the failure of these tests to yield reliable data:

- Much of the fracture fluid (water) remains in the gas-bearing formations and this fluid limits the volume of gas flow into the well when the pressure is lowered. The fact that fluid rises in the wellbore may be confirmed where a rate-dependent differential pressure is noted between the tubing and casing.

- Gas production at low formation pressures is predominantly from desorption of the gas from the shale surface. In this case, conventional analytic techniques are not applicable since the flow is no longer described by the reservoir engineering equations used in conventional test analysis.

If bottom-hole pressure recorders had been used, it would have been possible to distinguish between fluid level changes and the possible desorption phenomenon. Table 2-2 (Section 2) is a summary of the fracture treatment volumes for the eight wells. It can be seen that for the five wells where fluid recovery was measured, the frac fluid remaining after clean-up varies. A remaining volume from 2.5 to 4.1 times the casing volume for the Houghton #2 and Portville wells was calculated. Thus, there is evidence for believing that fluid entry caused much of the problems during test analysis.

The Houghton #1, the Valley Vista View, and the Meter wells were the only wells tested using a larger choke size. The remaining five wells displayed such low-flowing well-head pressures on the smallest available (1/16 inch) choke size that it was assumed an increase in choke size would have lowered the minimum operating pressure below the approximately 33 psia required to maintain sonic velocity at the choke. Of the three wells tested on two choke settings, the increased choke size caused an increase in the apparent drawdown pressure of between 25-30% with a corresponding increase in production rate of 12-14%. Further, analysis of a graph (Horner build-up curve) of gas potential m(p) plotted against the logarithm of flowing time (corrected for rate change) showed that the slope of the line decreased with increasing rate. The implication was that the permeability was higher at a lower formation pressure. Once again, it is believed these results were a function of changing fluid levels which attenuated the surface pressure change in relationship to bottom-hole conditions. This is further evidence of the negative impact the fracture fluid has on test data reliability.

It was concluded that if a straight line portion of the Horner build-up curve were observed, (after wellbore storage effects had died away) this would prove to be the best technique to evaluate permeability-thickness and apparent skin damage.

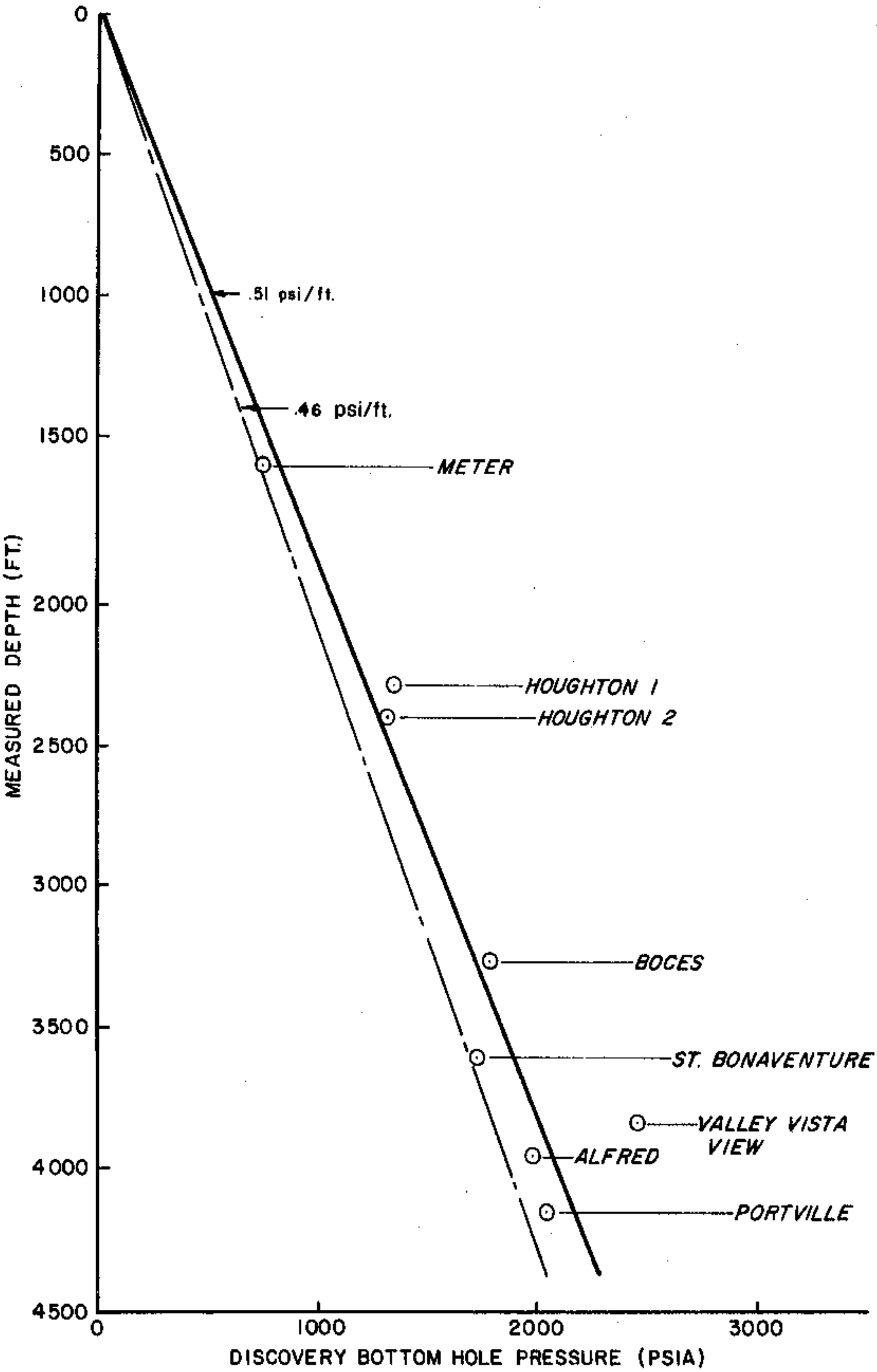
The appearance of such a straight line implies that the wellbore fluid has been taken into the formation, and that the surface and bottom hole pressures are moving in concert.

The straight line portion of the Horner build-up curve was apparent in only three wells (Valley Vista View #1, Houghton College #1, Houghton College #2); the calculated formation parameters are given in Table 4-1. In the other five wells it was necessary to assume an apparent skin factor of -2.3. The associated permeability-thickness can then be estimated from the pseudo steady state flow measurements in each well.

## FRACTURE TREATMENTS

Table 2-2 (Section 2) summarizes the stimulation treatments performed on the eight wells. Sand, ranging in quantity from 50,000 to 80,000 pounds, was carried into the induced fractures with nitrogen foam. Typically from 1 to 1.25 MMSCF of nitrogen was used to create the 75% quality foam used as a carrier. Fracture pressures were as high as 1.5 psi/feet; more generally they were in the range of 1.2-1.3 psi/feet. Using some simplifying geometric assumptions, fracture lengths were calculated to be between 200 and 300 feet. The negative skin factors derived from pressure surveys indicated the fracture treatments were effective and, in view of the low reserve estimates, may have been overdesigned. However, it is not recommended that the size of future treatments be reduced. Pressure control is essential to prevent fractures from penetrating lower water-bearing formations which would increase the probability of fluid migrating to the wellbore.

Nitrogen foam fracturing greatly reduces the fluid volumes needed to propagate the fracture and is probably the most economic way to handle future treatments. However, a methanol additive is advisable to increase fluid recovery after the treatment. Methanol will reduce the surface tension of the fracture fluid. Table 2-2 (Section 2) points out the inefficiency of the well clean-up procedures employed, whereby approximately half the frac fluid was left in the formation.




**MEASURED DEPTH VS. DISCOVERY PRESSURE**

**Fig. 4-1**

Table 4-1

WELL PERFORMANCE CHARACTERISTICS

| Well Name | Slope $((M)psia^2/cpx10^6)$ | Permeability Thickness (MD-ft) | Thickness (ft) | Permeability μ D | S |
|---|---|---|---|---|---|
| Valley Vista View | 8.5 | 3.25 | 15 | 216 | -2.0 |
| Houghton College #1 | 1.6 | 7.28 | 36 | 203 | -2.3 |
| Houghton College #2 | 16.1 | .14 | 34 | 4.1 | -2.6 |

The break in the slope at a P/Z of approximately 400 psia is indicative of the start of desorption in a typical shale gas well. With only two pressure points available, the projected gas initially in place will be conservative. However, the volume to be produced through desorption is uncertain. The other unknown factor concerns abandonment conditions, since fluid accumulations in the bore hole lead to abandonment at a higher pressure than would otherwise be necessary.

A first approximation has been made of the reserves attributable to each well assuming that no desorption of gas will take place and that it will be possible to produce the wells down to atmospheric pressure. This represents a first step in quantifying these reserves and improved estimates can be made when additional pressure measurements are taken over time. The results are shown for the individual wells in Appendix A and have been summarized in Table 2-1 (Section 2).

DELIVERABILITY

Of the eight wells tested, five failed to have sufficient deliverability to allow sustained flow with more than one choke size. The remaining three wells exhibited performance apparently governed by wellbore fluid levels, rather than formation properties. Consequently, the test results cannot be directly applied to evaluate the future productivity from these wells.

The removal of fluid accumulations from the wells, whether native water or fracturing fluid which remains after treatment, is crucial to the successful continued production from the wells.

Until the wells can be tested under conditions of minimal fluid accumulation, no projections of deliverability are meaningful. Since there is no way of quantifying the rate of fluid entry into the wells, and it is this fluid entry which governs the wells' rate of production, no projections of well deliverability could be calculated.

## Section 5
## PROJECTIONS

### RESERVE ESTIMATES

In the absence of statistically significant rate-time plots and volumetric data, material balance calculations may be relied upon to produce an estimate of initial gas-in-place, and hence reserves. The simplest form of the material balance equation for a dry gas reservoir is:

$$\frac{P}{Z} = \frac{P_i}{Z_i} \frac{(G-Gp)}{G} \qquad (5\text{-}1)$$

where P = pressure

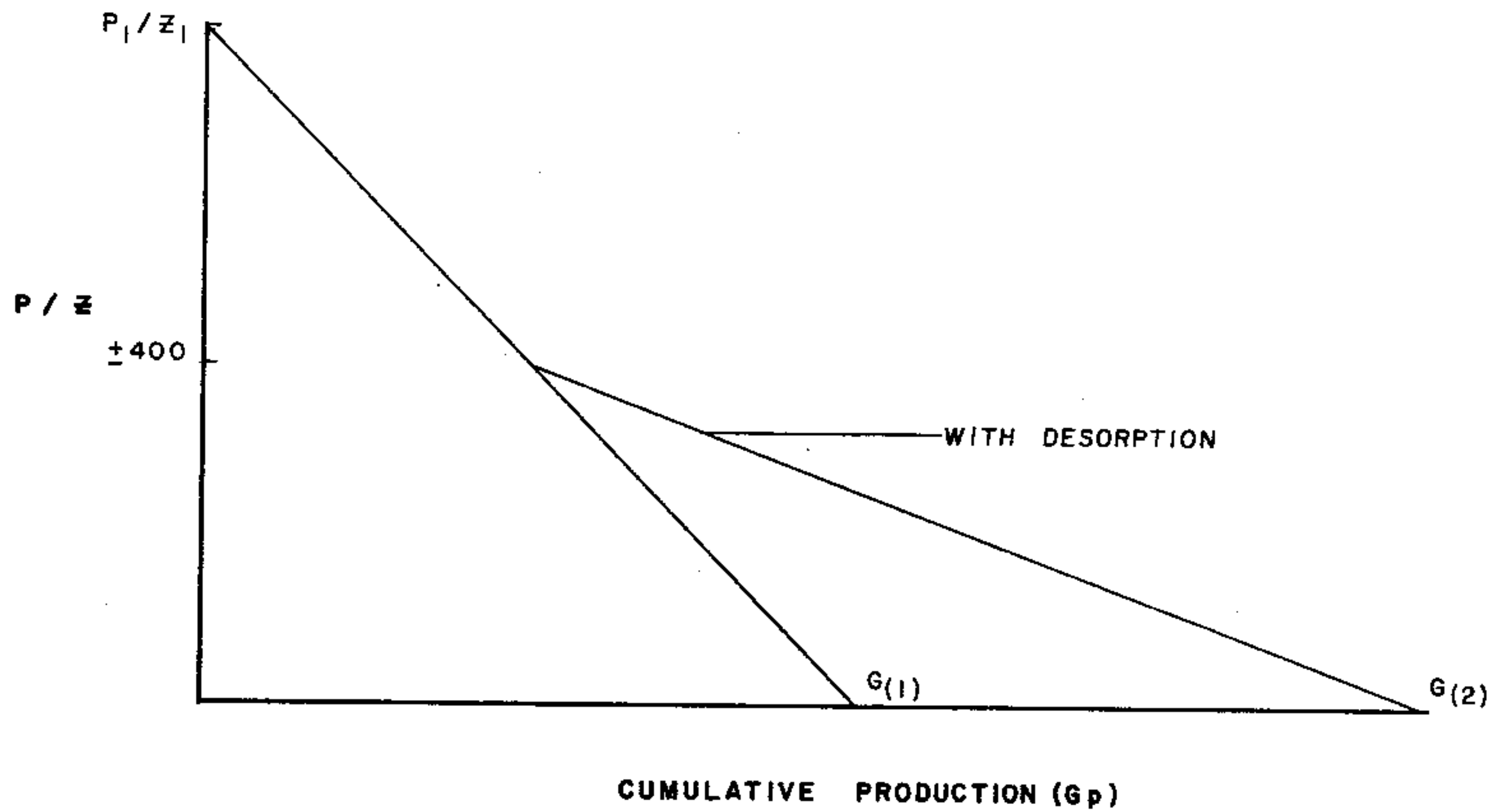
Z = gas deviation factor

G = initial gas in place

Gp = cumulative gas production

i = initial

The equation implies that a plot of P/Z versus cumulative production should be a straight line which can be extrapolated to yield initial gas-in-place at the end of the economic life of the well (abandonment conditions). This type of analysis relies on observed data to ensure that the reservoir is indeed a dry gas volumetric system. Measured initial pressures were available for the eight subject wells along with the inferred pressures from the well tests performed as part of this project, and a straight line has been fit to the data. It is known that shale gas wells normally exhibit two distinct slopes when this type of plot is prepared. Figure 5-1 illustrates typical shale gas well performance.




**TYPICAL SHALE GAS WELL PERFORMANCE**

**Fig. 5-1**

## APPENDIX A

## TEST DETAILS OF THE EIGHT WELLS

VALLEY VISTA VIEW

Introduction

The Valley Vista View well, located in Steuben County, was drilled to a total depth of 3848 feet, and completed in the Marcellus shale through perforations of the production casing from 3820 to 3835 feet. The well was subsequently deepened to 3910 feet leaving 62 feet of open hole below the 4 1/2-inch production casing. A well schematic is shown in Figure A-1.

A nitrogen-foam, hydraulic fracturing treatment was performed on the Marcellus shale interval in October 1980 followed by a modified isochronal test in November 1980.[1/] The Rhinestreet interval, 940 feet to 1225 feet, was isolated, stimulated, and tested in December 1980 and January 1981. The zone was found to be non-commercial and was sealed off. The well was finally completed in March 1981 in the Marcellus shale.

The Marcellus shale was fractured using a nitrogen foam carrier and propped with 8000 pounds of 80/100 mesh sand followed by 72,000 pounds of 20/40 mesh sand, increasing from 1 pound/gallon to 3 pound/gallon proppant concentration during a five-stage treatment. In March 1981 the well was tested at 127 MMCF/D during a 32-hour flowing period, with a shut-in casing pressure of 1,722 psig after 421 hours.

Commercial production commenced in December 1982 and was suspended in April 1983 with a cumulative withdrawal of 1.451 MMCF. Adding in approximately 224 MSCF during the first test and 169 MCF for the second test, the total withdrawal was 1.844 MMSCF at the onset of the current test.

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[1/]The November 1980 modified isochronal test results were used to develop the testing procedure. The analysis and recommended test procedure have been included in Appendix B.

Pressure Test 1983

A wellhead pressure of approximately 510 psig recorded during April 1983 indicated a substantial drop from the initial pressure of 2156 psig recorded in November of 1980. In April 1983, a fluid level test indicated the presence of about 900 feet of fluid with a casing pressure of 570 psig, and a swabbing unit was requested to remove the fluid. The well was swabbed on June 10, 1983, at which time about 23 BBls of fluid were removed, and the surface pressure reached a stabilized value of 872 psig by July 18, 1983.

The well was opened to atmospheric pressure via a 1/16-inch choke on July 18, 1983, and flowed continuously for 104 hours. The final flowing presure was 375 psig corresponding to a final flow rate of 30.5 MMSCF/D. The well was briefly shut-in, the 1/16-inch choke was replaced by a 3/32-inch choke and the well was flowed for an additional 137 hours. At the end of the second flow period, the flowing presure was 172 psig corresponding to a rate of 31.5 MSCF/D. The well was shut-in, and the pressure build-up was monitored continuously for 1,500 hours (62 days).

Figure A-2 shows the surface pressure recorded during the flowing periods. During the first flow period, a ripple of $\pm 7$ psi can be seen which is thought to be a result of hydrate formation during the relatively cold nights (45-55°F). The ripple disappears when the larger 3/32-inch choke is used. Figure A-3 is a smoothed plot of the computed production rate during the flowing period.

Figures A-4 and A-5 are semilog plots of the computed bottom-hole real gas potential m(p), plotted against the logarithm of flowing time corrected for the change in rate. The conventional Horner build-up plot, and the log $\Delta m(p)$ versus log $\Delta t$ plot are shown in Figures A-6 and A-7, respectively. The log $\Delta m(p)$ versus log $\Delta t$ was used to identify the flow regimes and the time intervals that could be amenable to specific analysis techniques. The unity slope portion of Figure A-7 is indicative of wellbore storage domination, during which time the downhole production rate has changed little from the rate prior to shut-in. The half slope portion of the curve is generally accepted as the linear flow portion of the curve and is indicative of flow from fractures. This is the most difficult portion to identify and analyze since a convex curve, which starts with a slope of unity and continues to flatten, will always have a portion that displays half slope. The final portion of the plot is indicative of radial or quasi-radial flow which can be used to evaluate the formation properties at some distance into the formation.

Figure A-6 is a conventional Horner plot which was used to analyze the formation properties after a shut-in time of 40 hours. The final increase in pressure was assumed to be the tighter matrix production finally making a significant contribution to the wellbore pressure.

## Summary of Test Results

Table A-1

WELL PRESSURE DATA

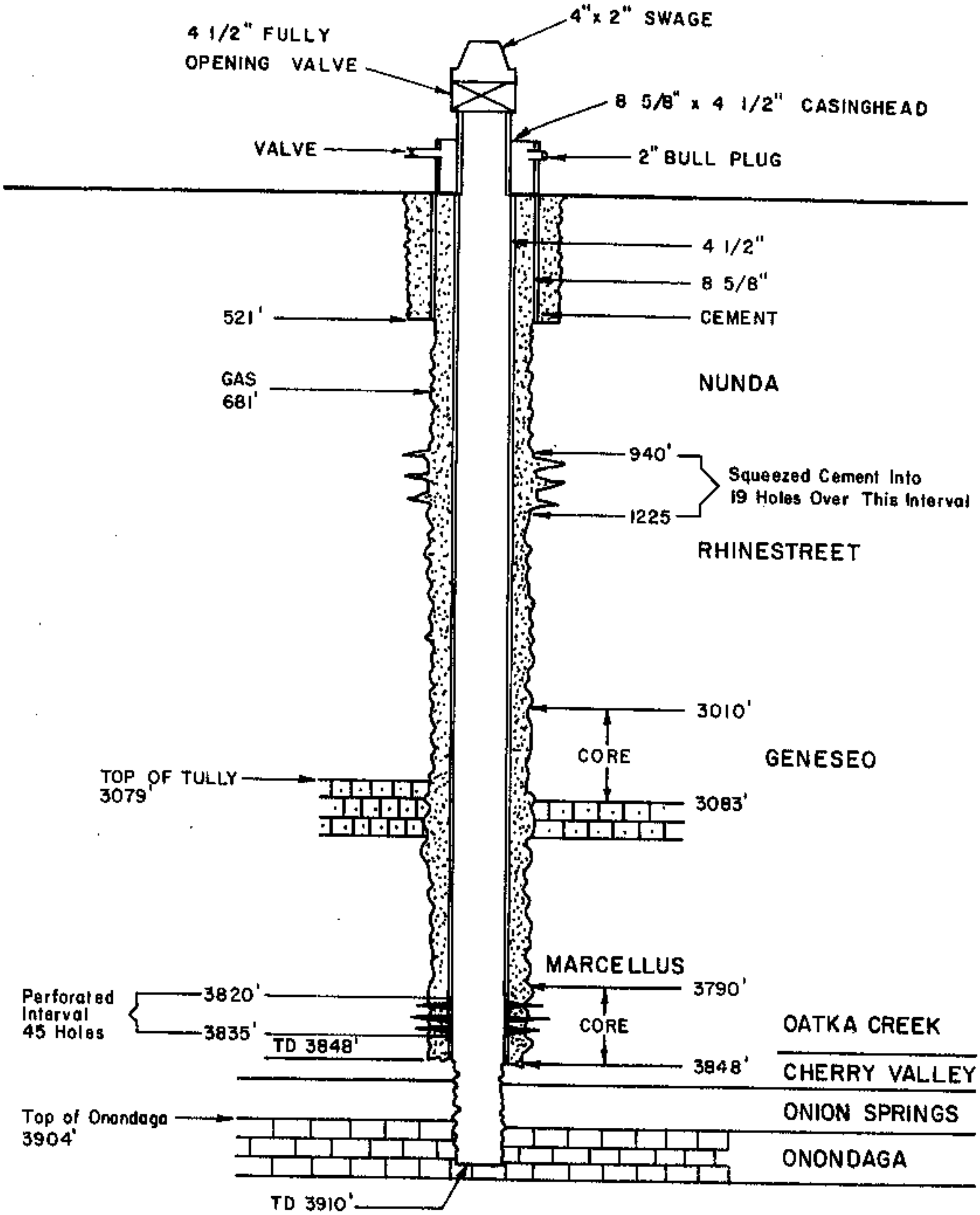
| Description | Figure | Qg MMSCF/D | Slope psia 2/cp log cycle | Permeability | Skin Factor |
|---|---|---|---|---|---|
| 1) Single rate drawdown | A-4 | 30.0 | $2.85 \times 10^6$ | 0.644 | - |
| 2) Variable rate drawdown | A-5 | 31.8 | $1.25 \times 10^6$ | 1.47 | - |
| 3) Horner | A-6 | 31.8 | $8.5 \times 10^6$ | .216 | -1.97 |

The simplest explanation for the large discrepancy between the permeability derived from the build-up and drawdown tests is to assume a changing fluid level which masks the effects of the formation pressure.

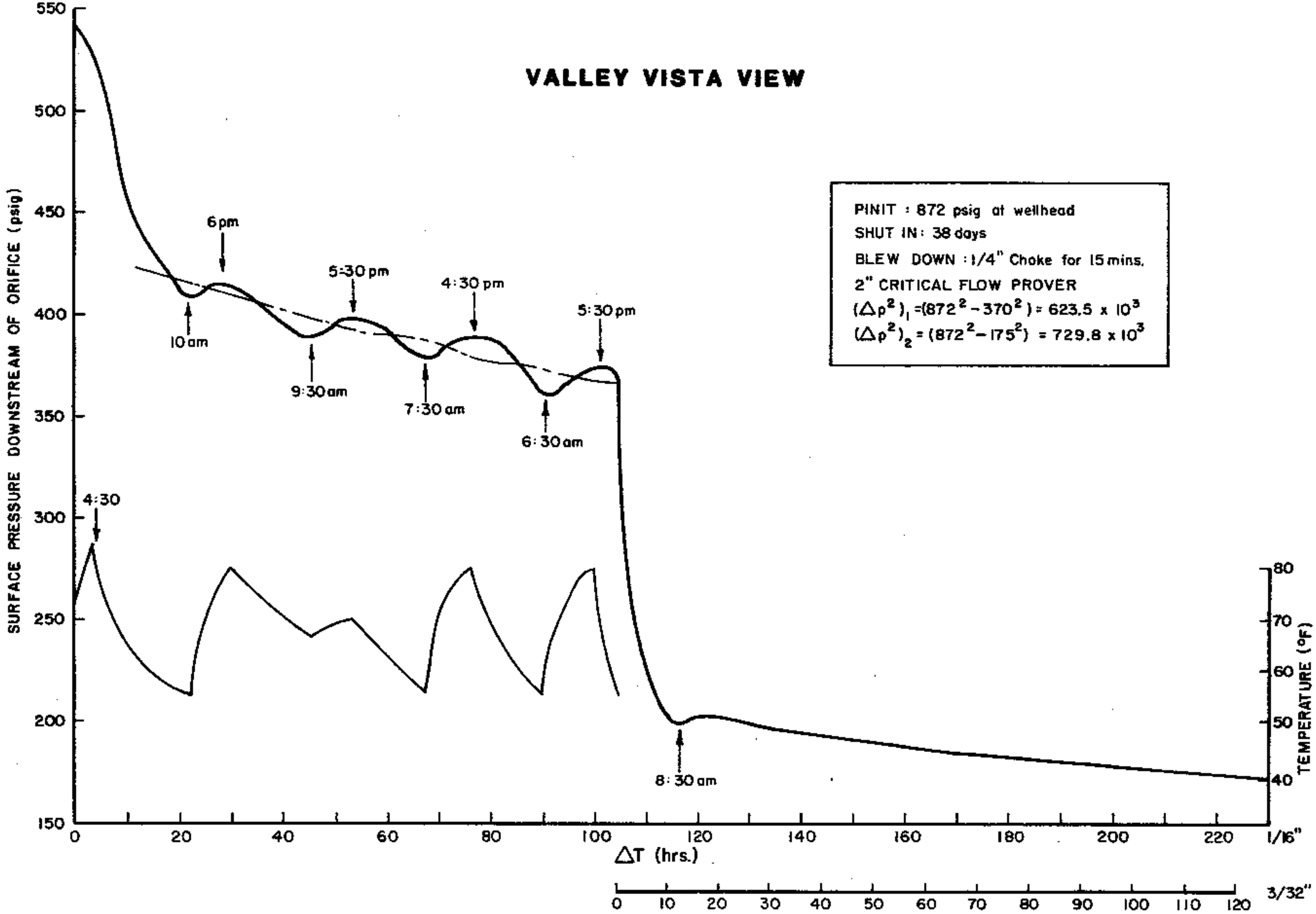
Reserve Estimate

Table A-2 summarizes the historical well pressure data. An attempt was made to quantify the potential corrections to be made when converting to bottom-hole conditions. Figure A-8 is a plot of reservoir pressure divided by the gas deviation factor (P/Z) versus cumulative production. It can be seen that the initial P/Z value appears to be too high which was confirmed by Figure 5-1 of the main report. Using a value of 0.51 psi/ft yields an initial P/Z value of 2812 psia which is much closer to a straight line fit. Initial gas-in-place estimates were 3.32 and 5.32 MMCF with remaining reserves between 1.17 and 3.17 MMCF.

# VALLEY VISTA VIEW , INC. #1

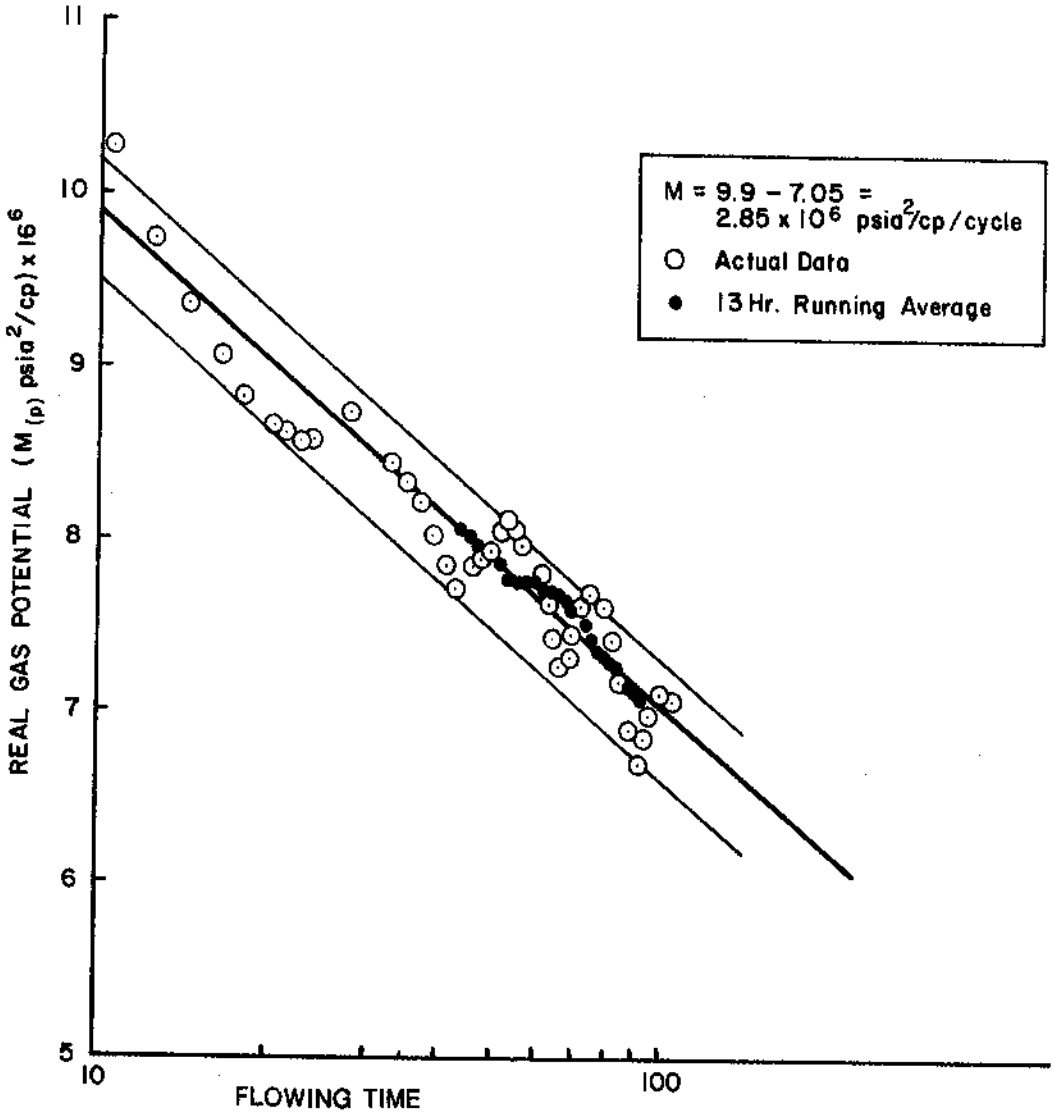



**WELL SCHEMATIC**
**Fig. A-1**



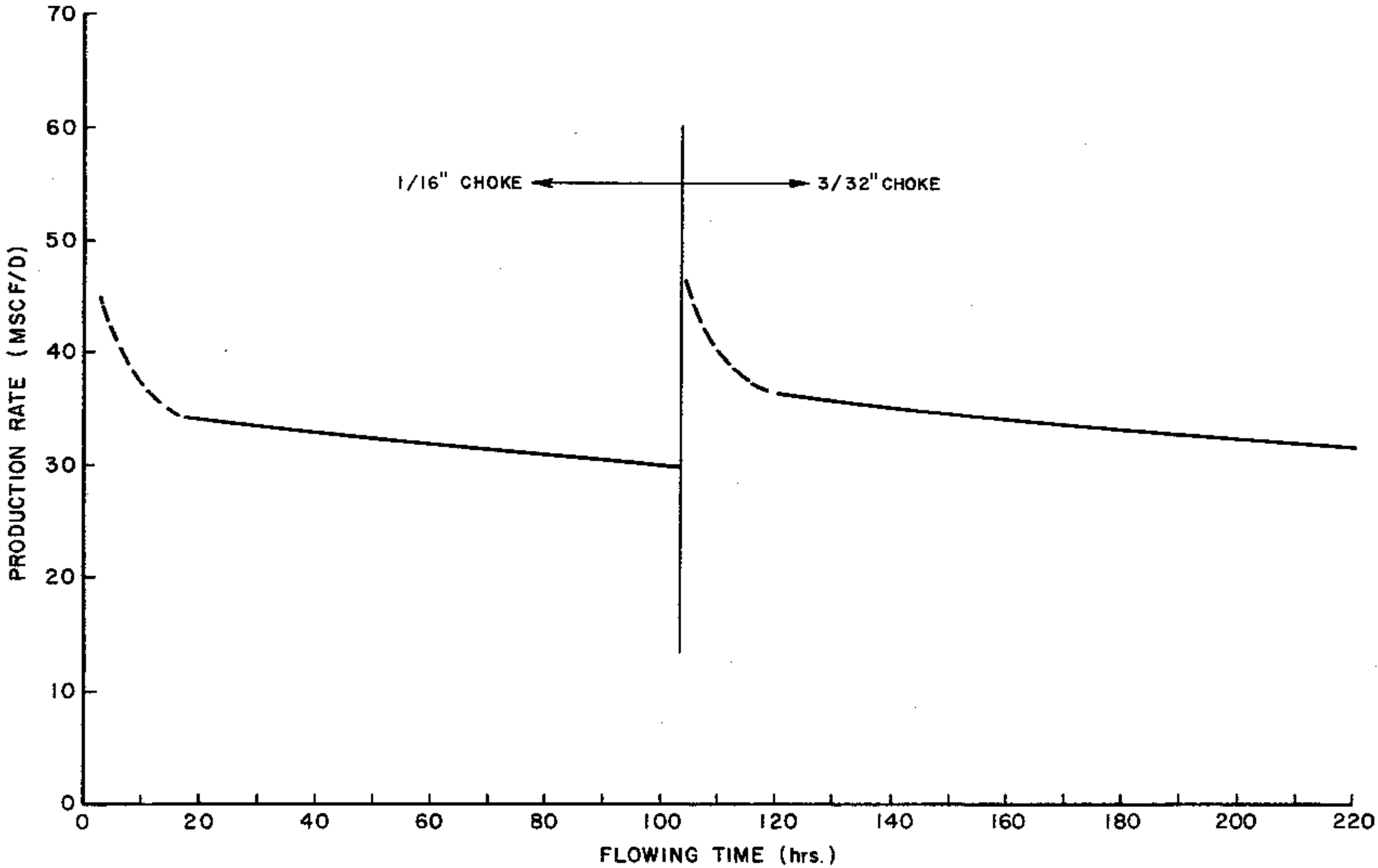

**RAW DATA**
**Fig. A-2**

## VALLEY VISTA VIEW



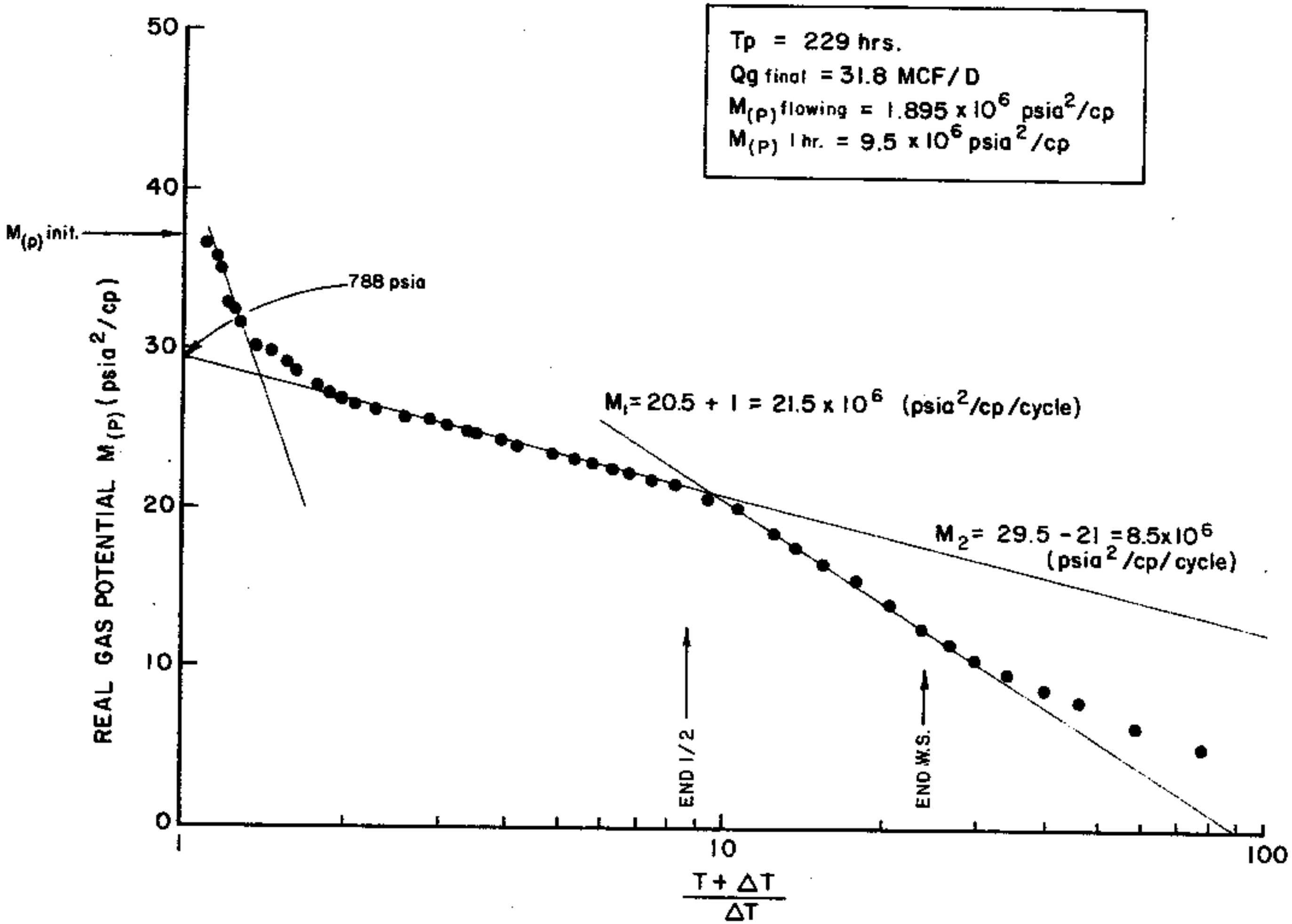

**DRAWDOWN 1/16" CHOKE**
**Fig. A-4**

COMPUTED PRODUCTION RATE
VALLEY VISTA VIEW




DRAWDOWN TEST
Fig. A-3

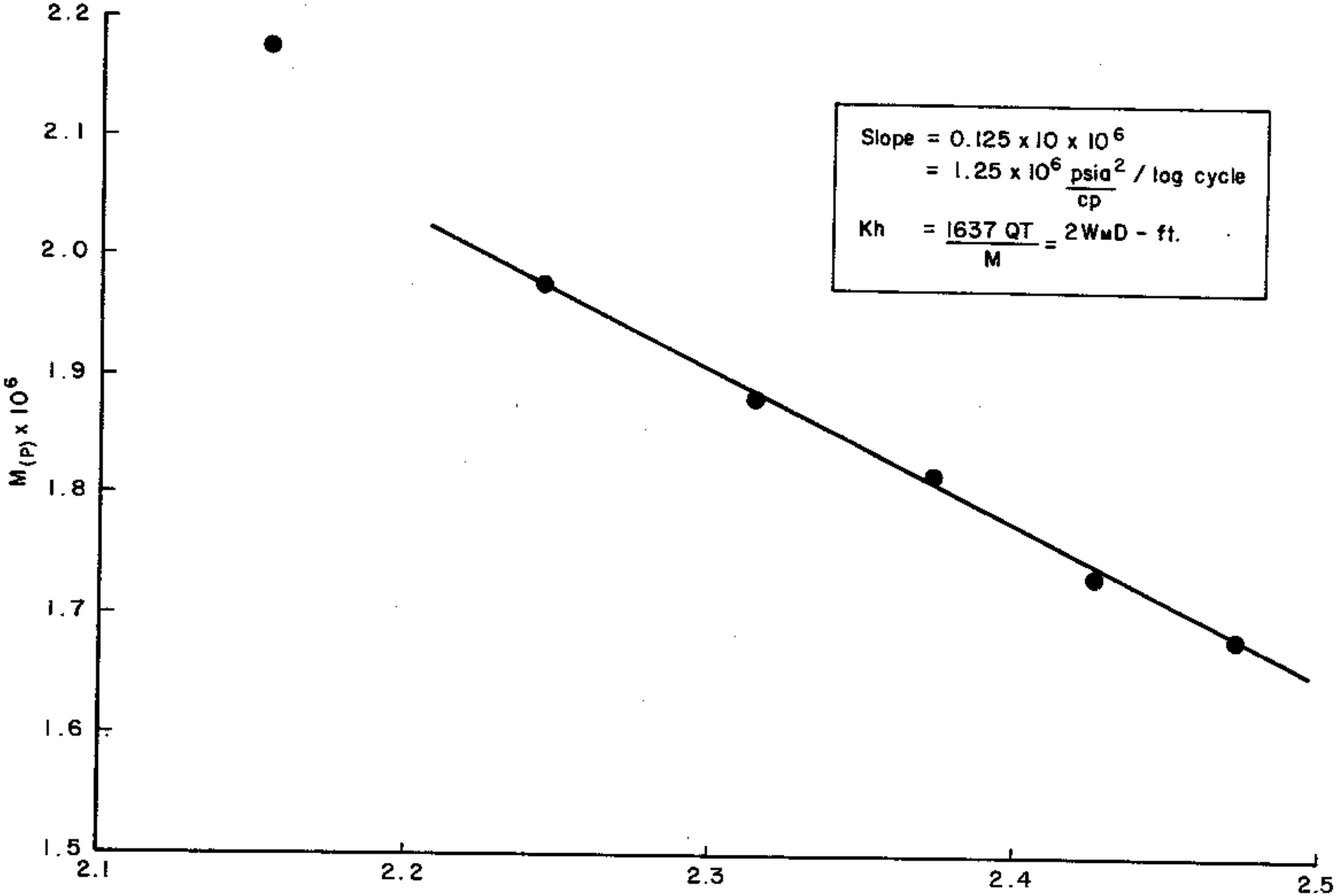
## VALLEY VISTA VIEW
## JUNE 1983




**HORNER BUILD UP**
**Fig. A-6**

VALLEY VISTA VIEW

**VARIABLE RATE PLOT**

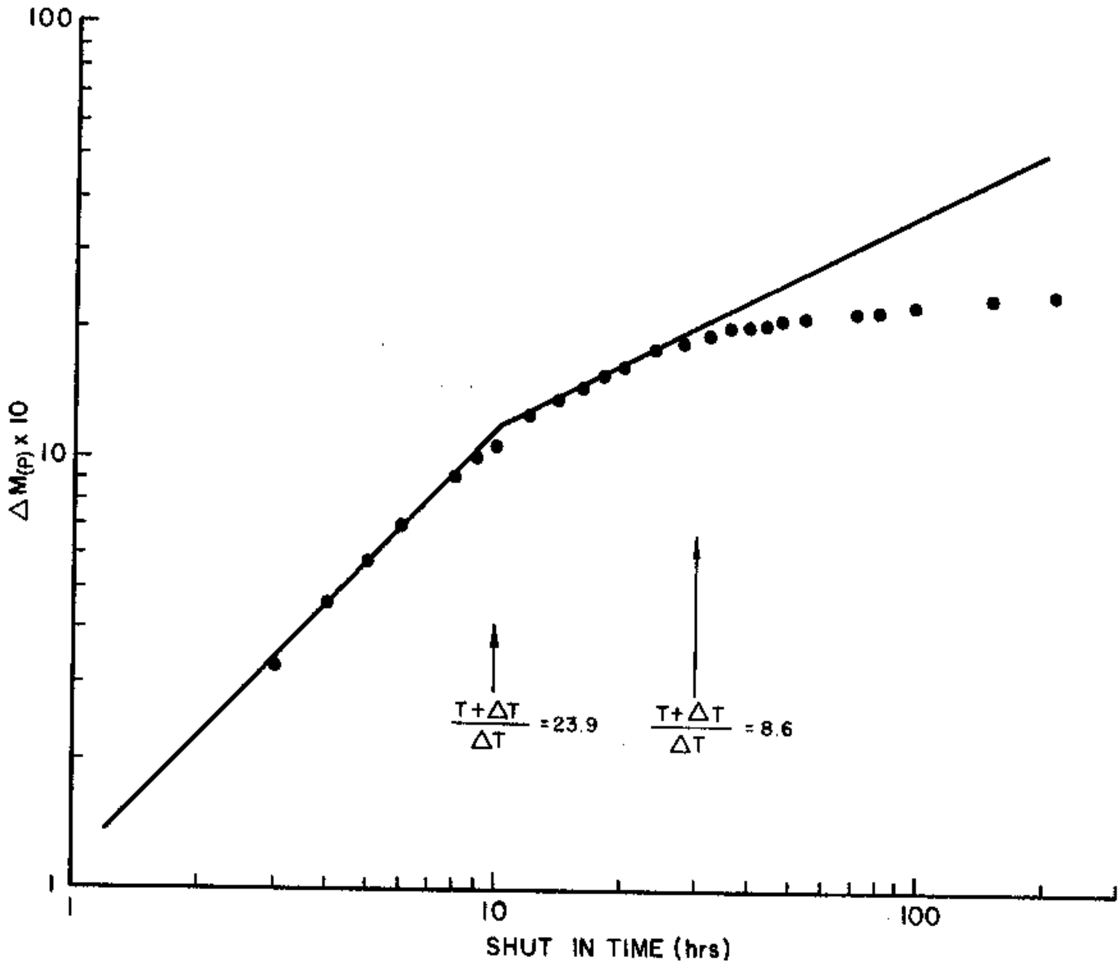



LOG $\frac{t+\Delta t'}{\Delta t'} + \frac{q_2}{q_1}$ LOG $\Delta t'$

**SECOND FLOW PERIOD**

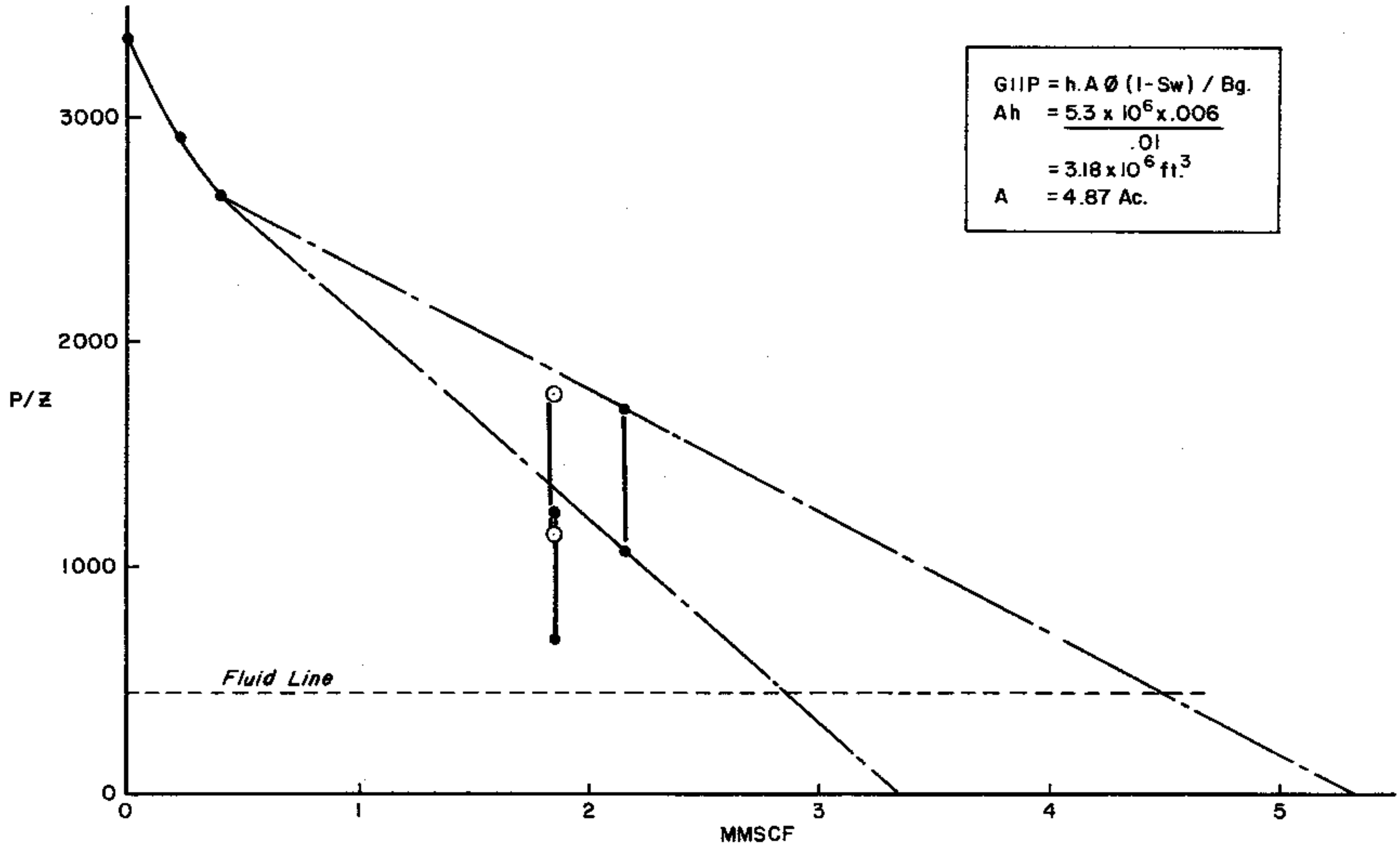
**Fig. A-5**

## VALLEY VISTA VIEW




**BUILD UP**
**Fig. A-7**

## VALLEY VISTA VIEW




**P/Z vs. CUMULATIVE PRODUCTION**
**Fig. A-8**

HOUGHTON COLLEGE #1

Introduction

The Houghton College Fee No. 1 well, located in Allegany County, New York, was drilled to a total depth of 2334 feet and completed in the Marcellus shale through perforations of the production casing from 2254 feet to 2292 feet. The well was stimulated using a nitrogren foam carrier and the fractures propped with 5,000 pounds of 80/100 mesh sand followed by 45,000 pounds of 20/40 mesh sand. An initial pressure test of 1,361 psia at bottom-hole conditions was recorded in October 1979. A well sketch is shown in Figure A-9.

A transient pressure test was run during March 1980. The test was single-rate (130 MCF/D) drawdown for 10 days followed by a four-day build up test. The initial and final bottom-hole pressures were 1,370 and 1,243 psia, respectively. The well was later completed with a single string of 1 1/2-inch tubing to a depth of 2,250 feet to permit the removal of wellbore fluids. Production began in November 1980 and the well has produced 21,173 MCF of gas on an "as needed basis" through March 1983.

Pressure Test 1983

The well was closed in on April 13th to achieve a stabilized pressure. On April 28th the casing pressure was approximately 348 psig as compared to the initial bottom hole pressure 1370 psia. This low pressure indicates a fluid build up in the casing. Attempts to remove any fluid were unsuccessful and it was concluded that the tubing contained only gas. The well recorded a stabilized casing pressure of 363 psig on June 1st, 49 days after the initial shut-in date.

The drawdown test consisted of an eight day flowing period, with the well producing against 1/16-inch and 3/32-inch chokes for 103 hours and 89 hours, respectively. The build-up was continuously recorded for 40 days, at which time the surface pressure was 371 psig.

Table A-2

SUMMARY OF PRODUCTION AND PRESSURES

| Test Date | Cumulative Production (MSCF) | Initial Surface Pressure | Highest Surface Pressure Recorded | Bottom-Hole Minimum Pressure | Maximum Hydrostatic Correction | Bottom-Hole Maximum Pressure |
|---|---|---|---|---|---|---|
| Nov. 1980[c/] | — | 2156 | — | 2440 | — | 2440 |
| Nov. 1980 | 224 | — | 1921 | 2167 | — | 2167 |
| Mar. 1981 | 393 | — | 1722 | 1938 | — | 1938 |
| April 1983 | 1844 | — | 570 | 612 | 416 | 1028 |
| July 1983 | 1844 | 872 | — | 967 | 416 | 1383 |
| Sept. 1983 | 2147 | — | 834 | 924 | 416 | 1340 |

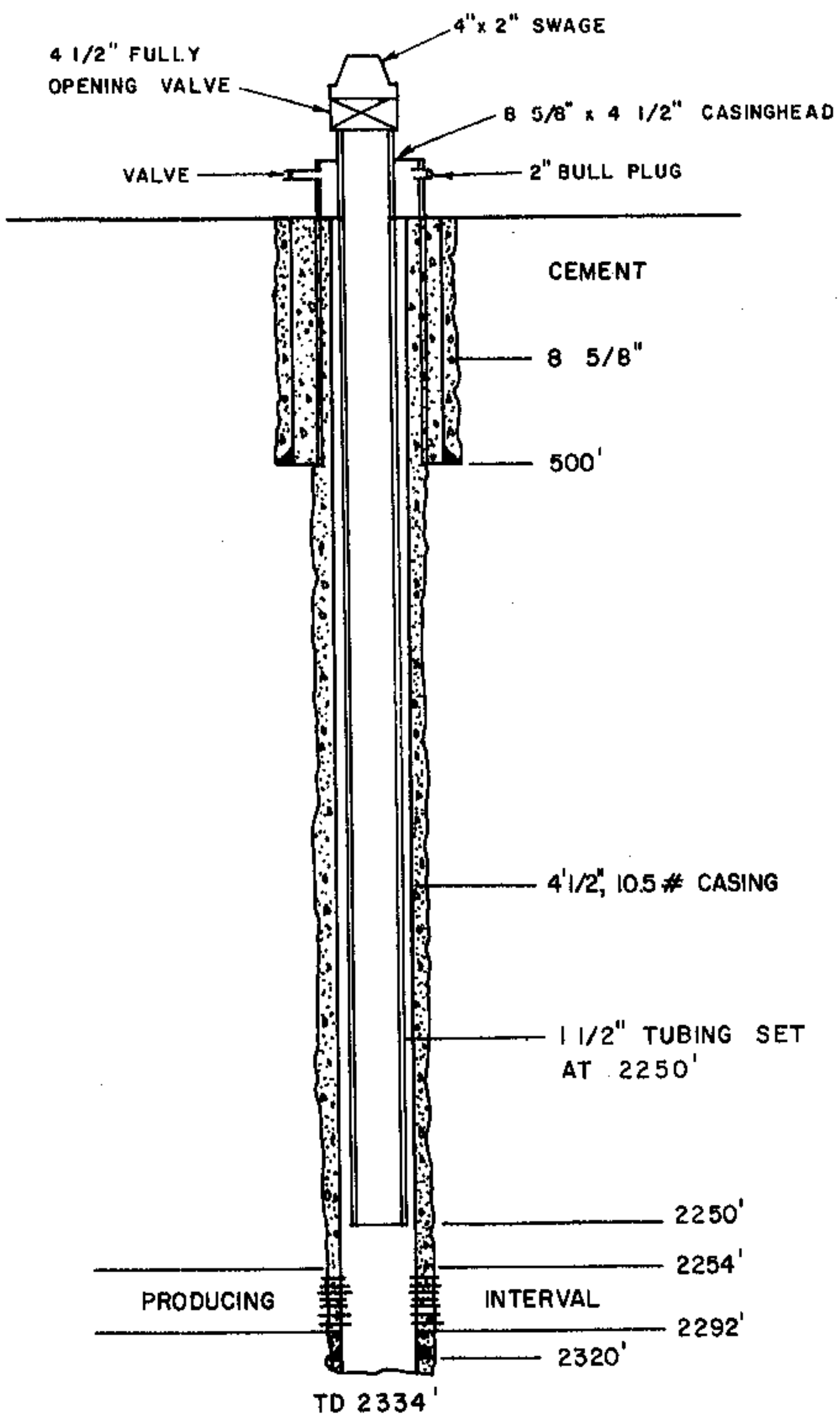
[c/] Over pressure gradient = 0.624 psi/feet possibly due to fracturing fluid

The calculated flow rate, shown on Figure A-10, indicates that the final rate was 11.5 MCF/D and 12.5 MCF/D for the 1/16-inch and 3/32-inch choke, respectively. During the test, maximum differential pressures of 84 psi and 127 psi were measured between the tubing and casing, indicating the presence of fluid in the annular space between casing and tubing of 186 feet during the first flow period and 282 feet of fluid for the second period. This effect can also be seen on the Horner build up plot (Figure A-12). The casing and tubing pressures came together after a shut-in time of 16 hours ($t+\Delta t/\Delta t=13.5$) indicating that the base of the tubing was uncovered and that the fluid had been pushed back into the formation. The subsequent straight line portion of the Horner build up curve was used to calculate a permeability thickness product of 7.28 MD-ft. Assuming an effective thickness of 38 ft yields a permeability of 203 $\mu$D and skin factor of -2.3. A plot of the log of the difference in pressures squared versus log shut-in time is shown in Figure A-11.

## Reserve Estimate

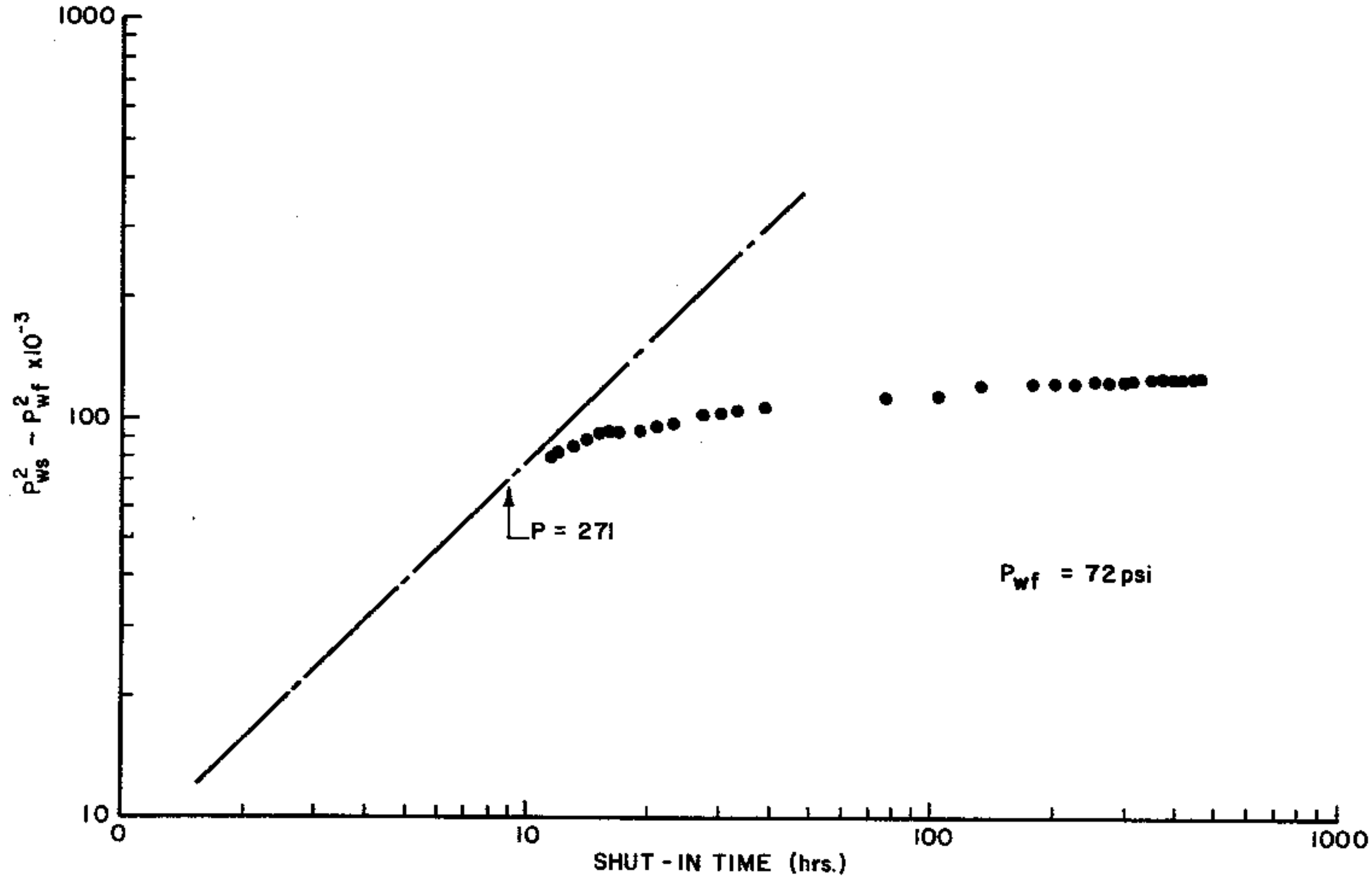
Pressure data were available from three tests: the initial pressure, the partially built-up pressure following the March 1980 test, and the fully built-up pressure taken from the 1983 test. A plot of pressure divided by deviation factor (P/Z) versus cumulative production is shown in Figure A-13. The plot suggests an initial gas-in-place of between 27.5 and 31.4 MMSCF, which corresponds to an appropriate area of 16 acres. The assumptions in the area calculation were 50 percent water saturation and two percent average porosity. Thus, remaining reserves are between 5.03 MMSCF assuming no influence of fluid; and 8.93 MMSCF if a fluid column of 282 feet is assumed.

## HOUGHTON COLLEGE FEE #1 WELL

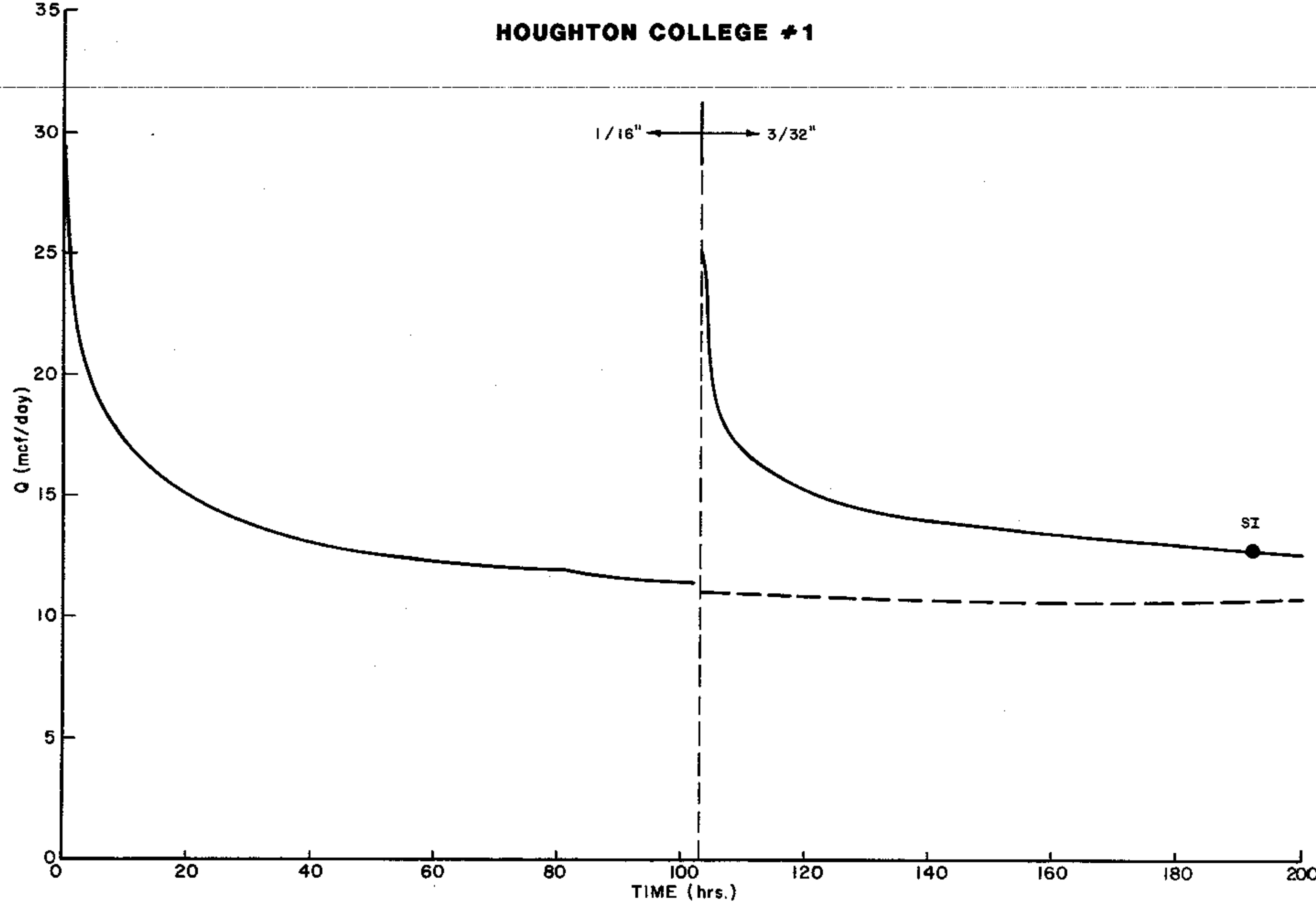



**WELL SCHEMATIC**
**Fig. A-9**

## HOUGHTON COLLEGE #1



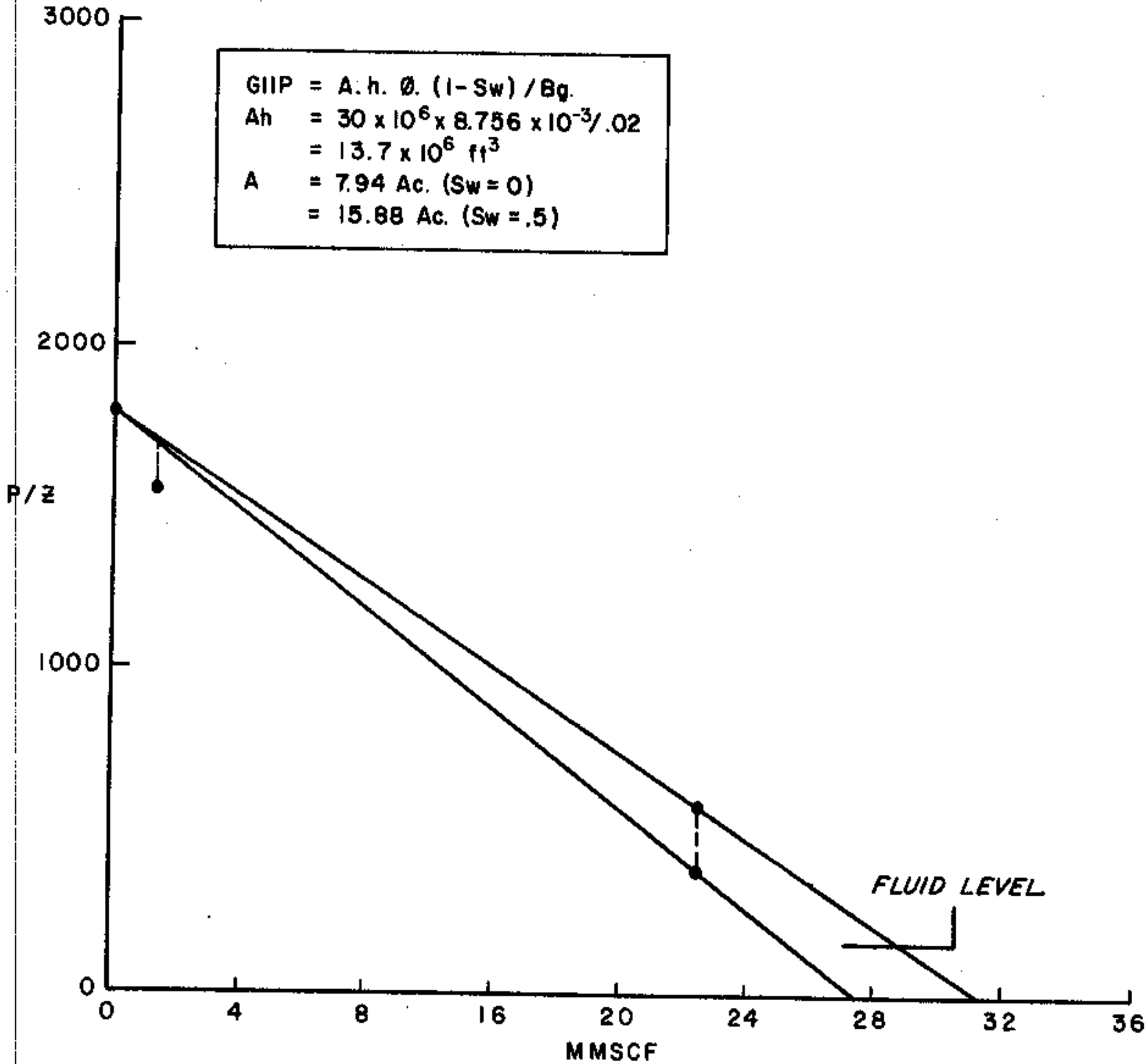

**BUILD UP**
**Fig. A-11**



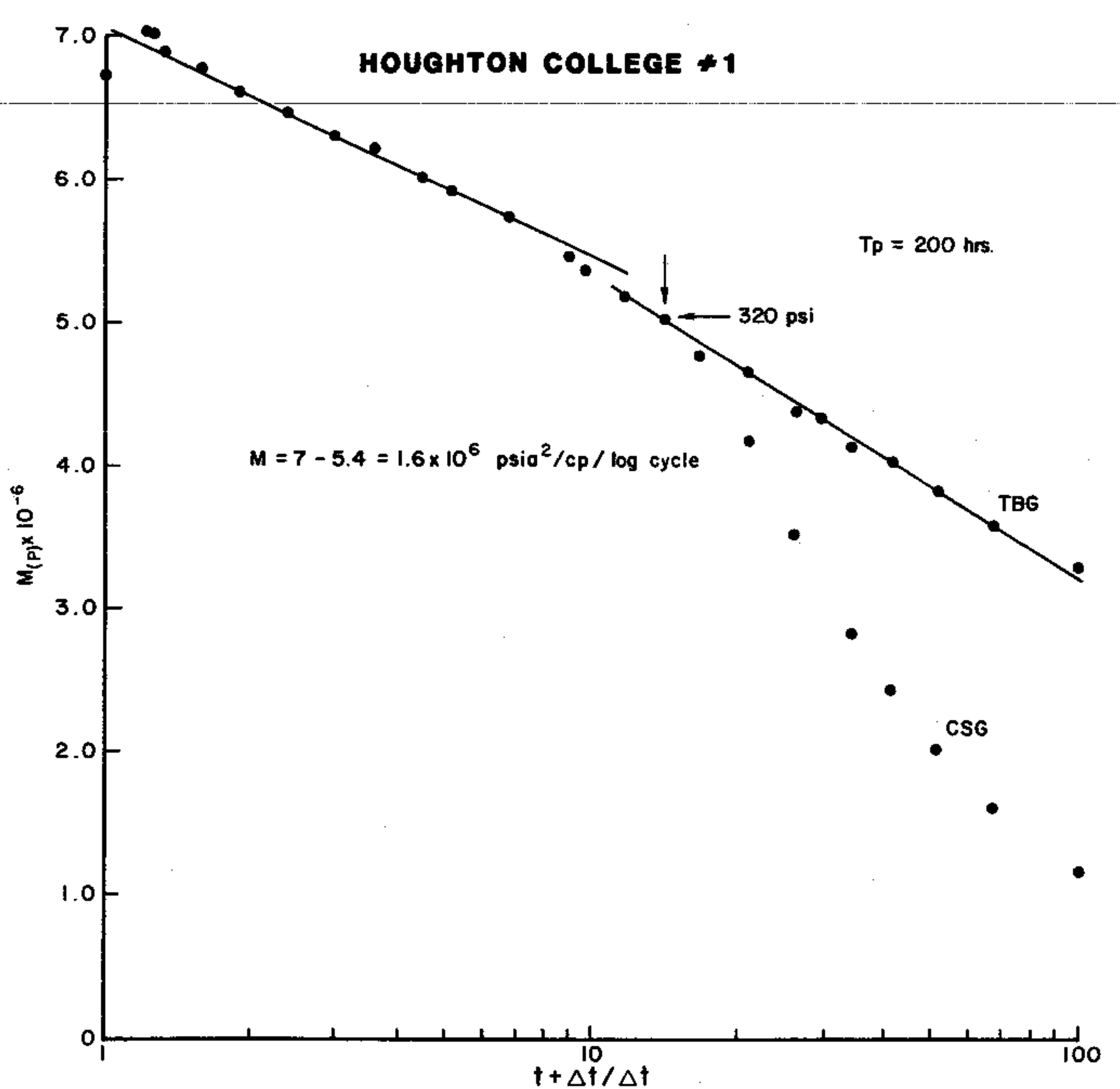

**DRAWDOWN TEST**

**Fig. A-10**

## HOUGHTON COLLEGE #1




**RESERVE ESTIMATE**
**Fig. A-13**




**HORNER BUILD UP PLOT**
**Fig. A-12**

METER WELL #1

Introduction

The Meter, Kennedy, and Howe Unit No. 1 well (Meter No. 1) was drilled to a total depth of 1,642 feet and completed through perforations of the production casing between 1,332 feet and 1,617.5 feet. The well was stimulated in November 1980 using a nitrogen foam carrier and the induced fractures were propped with 8000 pounds of 80/100 mesh sand followed by 68,000 pounds of 20/40 mesh sand. A well sketch is shown in Figure A-14.

Following swabbing and clean-up operations the well was tested. The extended drawdown (47 hours of a modified isochronal test) was followed by a 25 day buildup. The final shut-in pressure was 703 psig.

Production commenced in January 1982 and the well had produced 2.899 MMCF through February 1983. The well was swabbed in October 1982 because of low wellhead pressures; however, no fluid was recovered.

Pressure Test 1983

The well was shut-in from April 11th to September 20th, (131 days) in an attempt to achieve a stabilized shut-in pressure. At the end of the shut-in period the casing head pressure was 440 psig and was still building up at approximately 1 psi/day. Time constraints dictated that the well be tested. The well was flowed for a total of 260 hours, first against a 1/16-inch choke followed by a 3/32-inch choke. The first flow period was for 142 hours and the final flowing casing pressure was corresponding to 15.4 MSCF/D. At the end of the second flow period the casing pressure was 82 psig corresponding to 14.8 MSCF/D. Figure A-15 is a plot of the flow rate versus time for the two flow periods.

The well was shut-in on September 31st, and the build up was monitored for 96 days. The final casing head pressure was 455 psig. A plot of the log of the difference in pressures squared versus log shut-in time is shown on Figure A-16. In this particular test no unity slope was observed, but rather a straight line with a slope of 0.7 for a period of approximately 200 hours followed by a half slope for the duration of the test. The Horner plot (Figure A-17) reveals no information concerning formation parameters.

A linear flow analysis of the first and second flow periods yielded no useful results and it was concluded that the test had failed to determine the formation characteristics for one of two reasons:

- Fluid accumulation in the wellbore. During the drawdown phase, fluid had risen in the well. During the buildup phase of the test, fluid was injected back into the formation masking the true change in formation pressure.

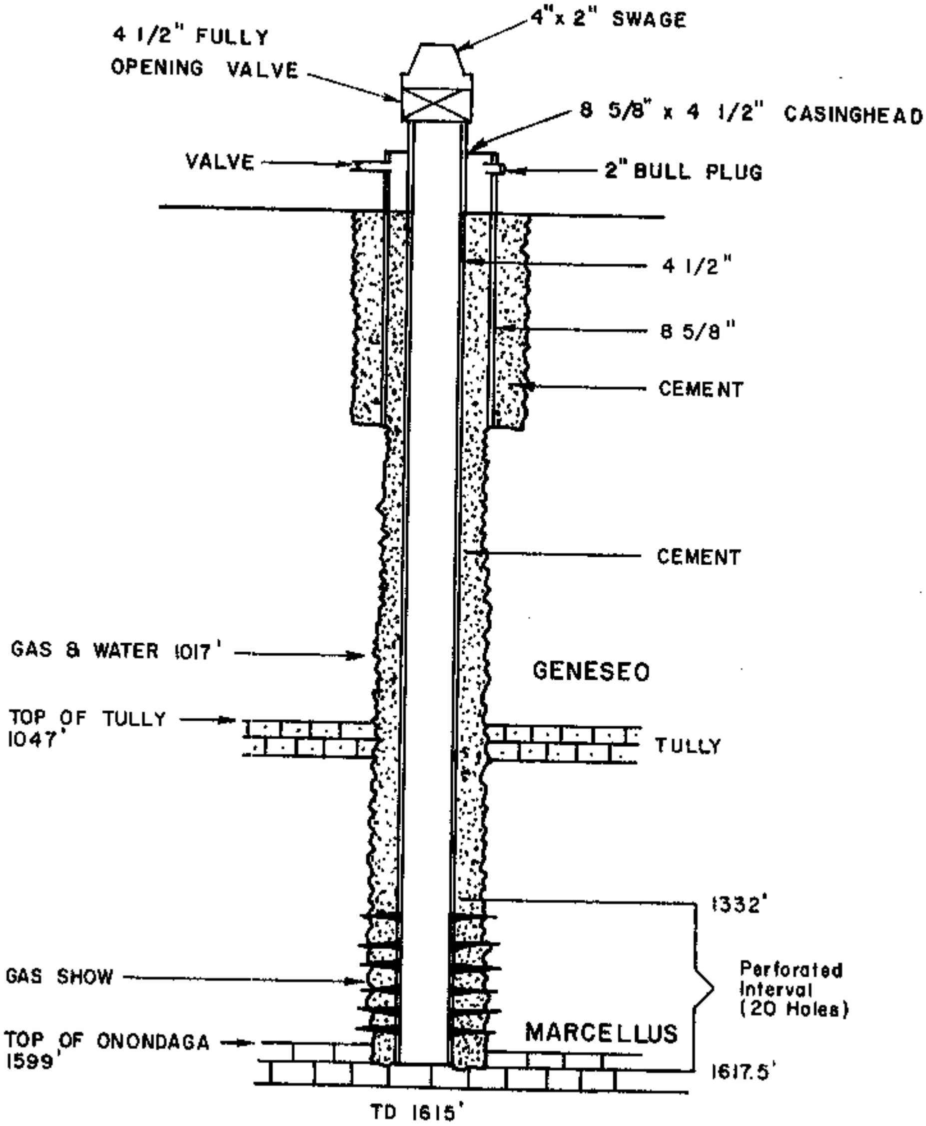
- The formation did not conform to the basic diffusivity equation on which conventional test analysis is based. This test is of particular interest as the well was the shallowest and therefore exhibited the lowest initial pressure of the eight wells tested. It is possible that the conventional test analysis failed to yield any useful results because the well's primary mode of production was by desorption. The other wells all showed a deviation from the initial unity slope on the log $\Delta m(p)$ versus log $\Delta t$ when the formation pressure reached approximately 450-550 psia. In the case of the Meter well this threshold pressure was not reached.

In the absence of either a bottom-hole pressure or a fluid-level measurement during the test it is impossible to say which of the above reasons caused the unusual buildup behavior.

## Reserve Estimate

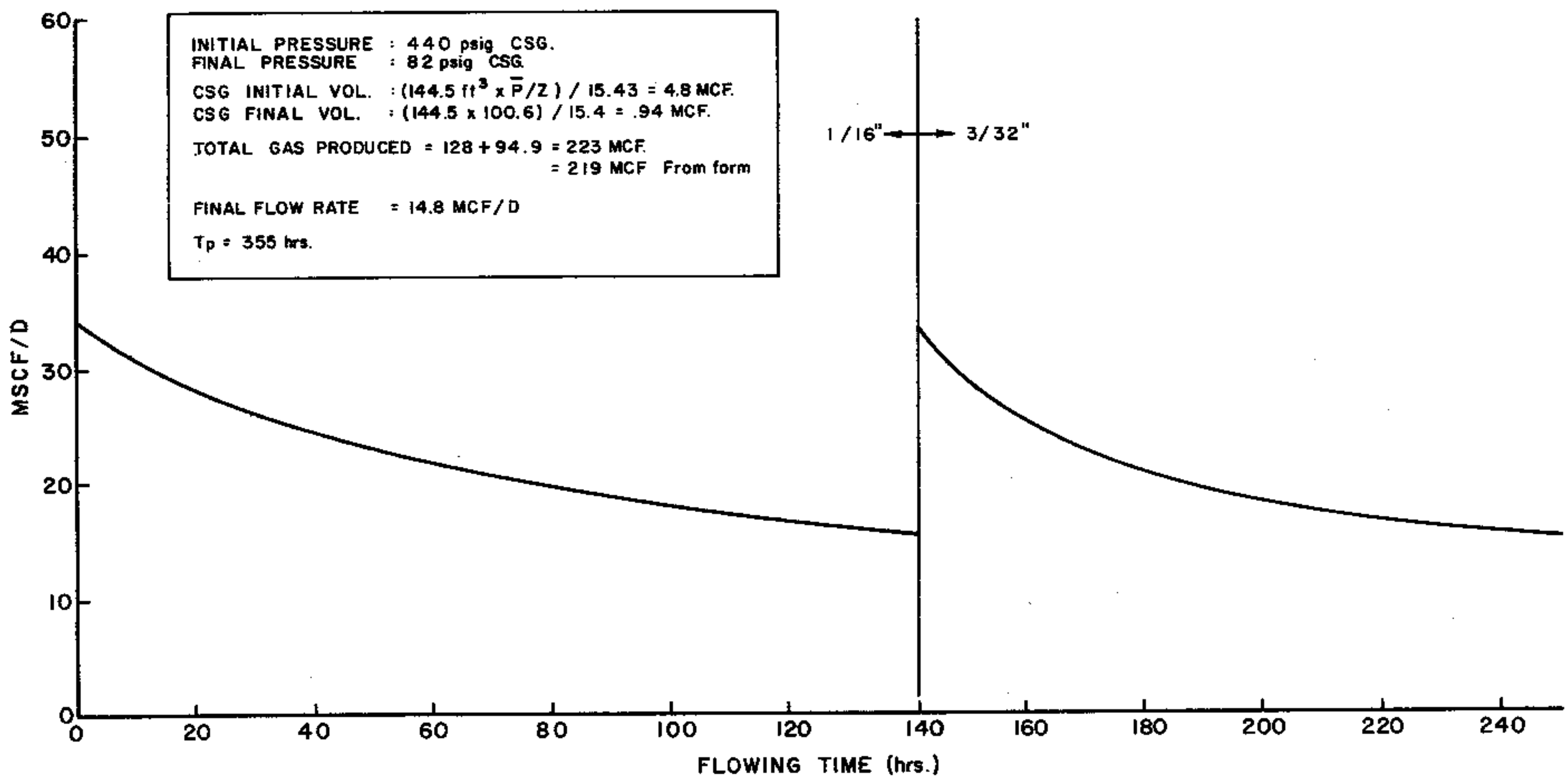
Figure A-18 is a plot of pressure divided by deviation factor (P/Z) plotted against cumulative gas production. The plot indicates an estimate of gas initially in place of between 7.25 and 10 MMSCF or a remaining gas reserve of between 4.13 and 6.78 MMSCF.

## METER, KENNEDY, HOWE UNIT #1 WELL



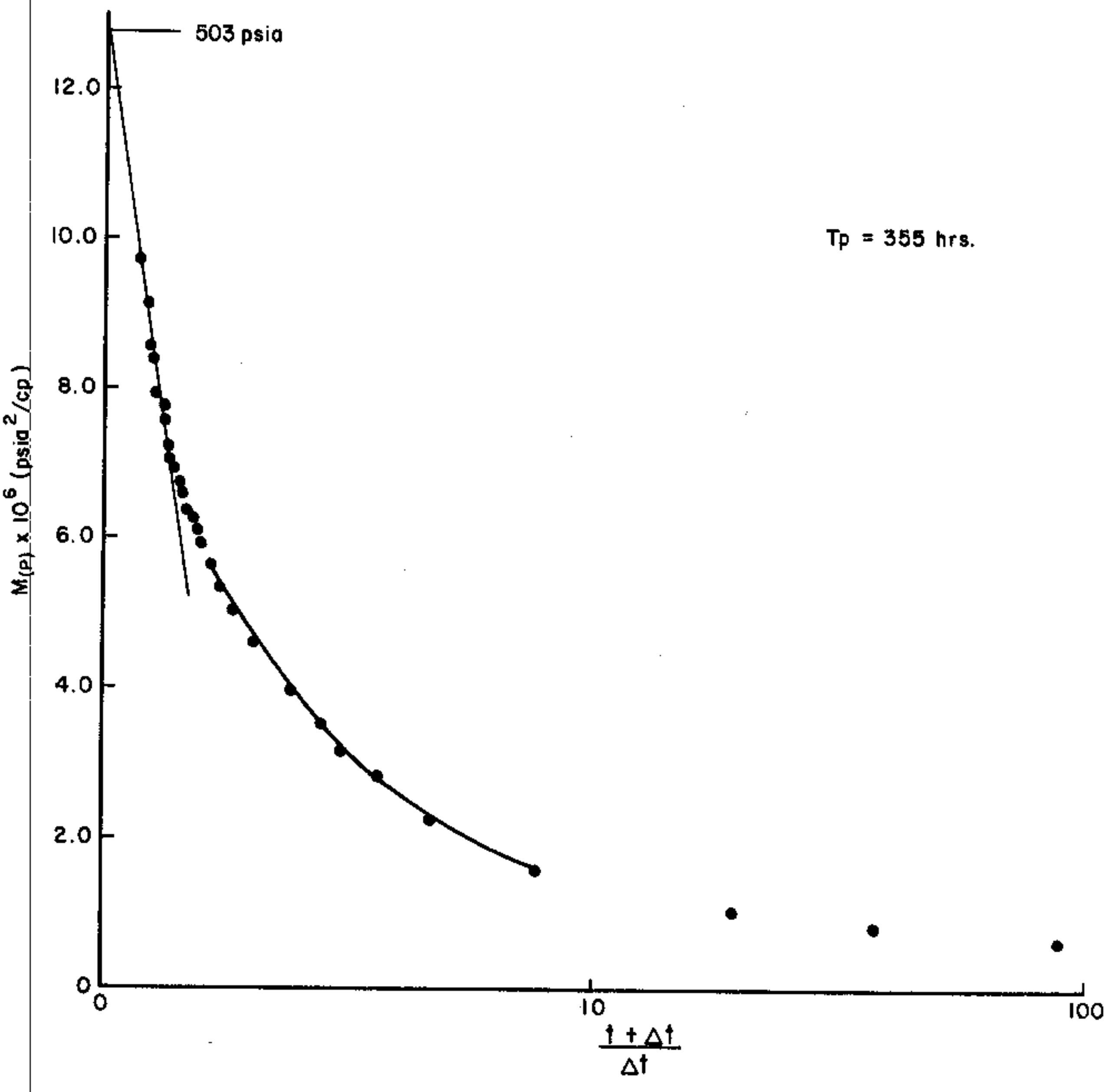

**WELL SCHEMATIC**
**Fig. A-14**

## FLOWING PERIOD FOR METER #1 WELL



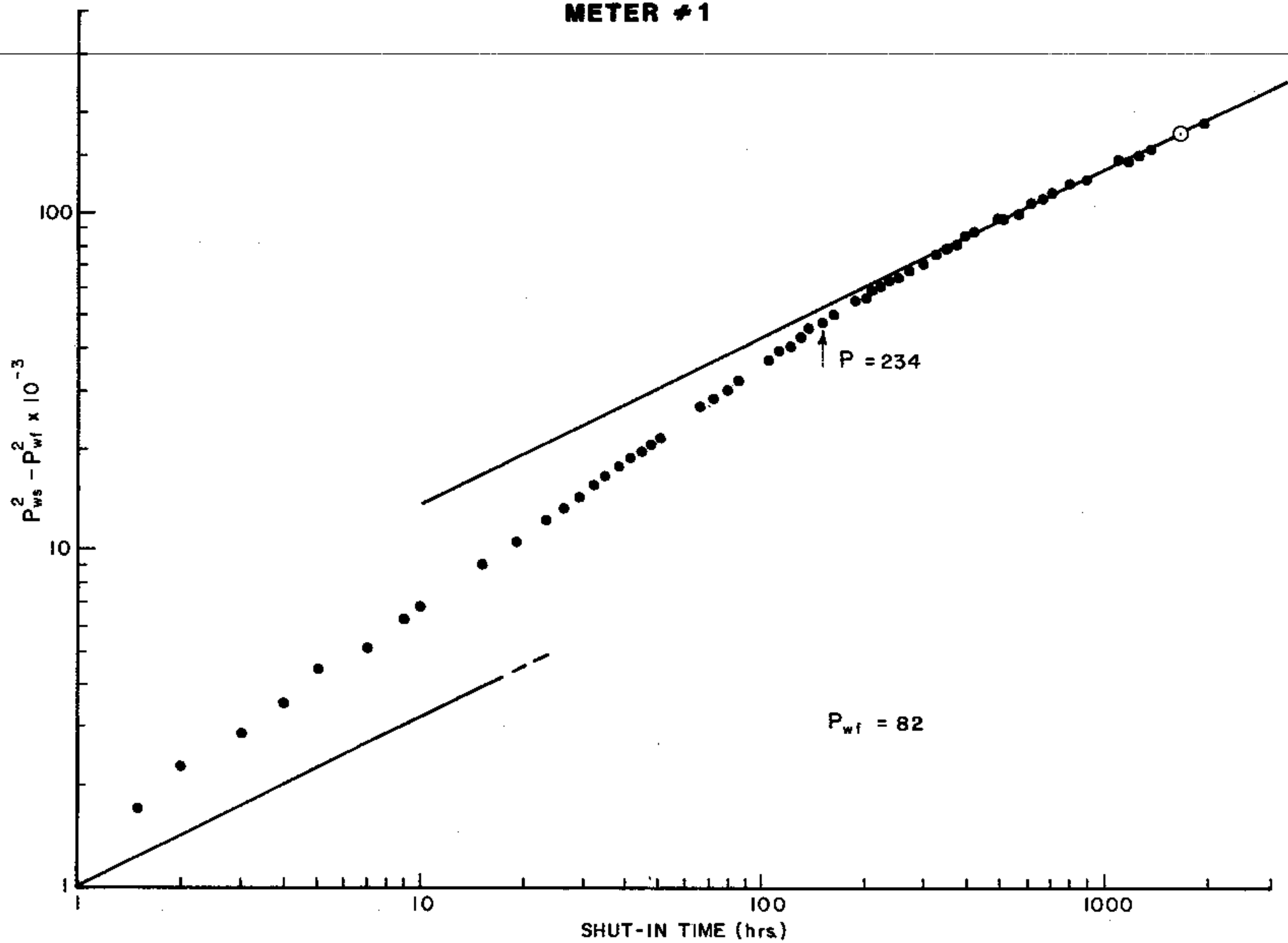

**DRAWDOWN**
**Fig. A-15**

## METER #1 WELL




**HORNER BUILD UP PLOT**
**Fig. A-17**

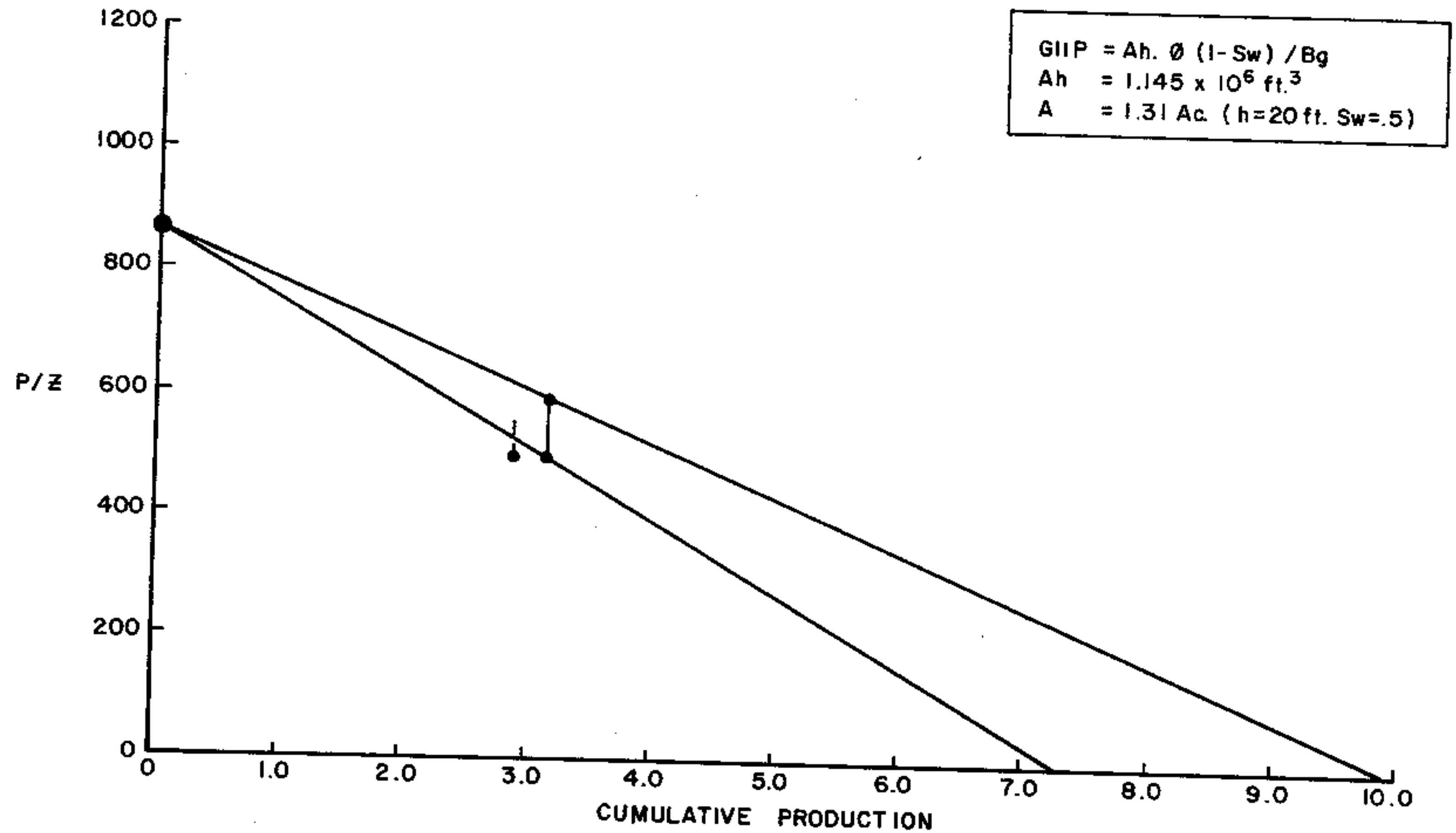
## METER #1




**BUILD UP**

**Fig. A-16**

METER #1 WELL




**RESERVE ESTIMATE**

**Fig. A-18**

HOUGHTON COLLEGE #2 WELL

Introduction

The Houghton College No. 2 Well located in Allegany County, New York was drilled to a total depth of 2,471 feet and completed in the Marcellus shale through perforations of the production casing between 2,382 feet and 2,416 feet. In August 1981 the well was stimulated using hydrofluoric acid followed by a nitrogen foam fracture process. The induced fractures were propped with 10,000 lbs of 80/100 mesh sand followed by 50,000 lbs of 20/40 mesh sand. A well sketch is shown on Figure A-19.

Following the initial clean-up and swabbing, the well was shut-in for approximately eight days. On September 20, 1981 the final shut-in casing pressure was 1220 psig.

Production began in January 1982 and the well has produced a total of 595 MCF of gas on an "as needed" basis to April 13, 1983.

Pressure Test 1983

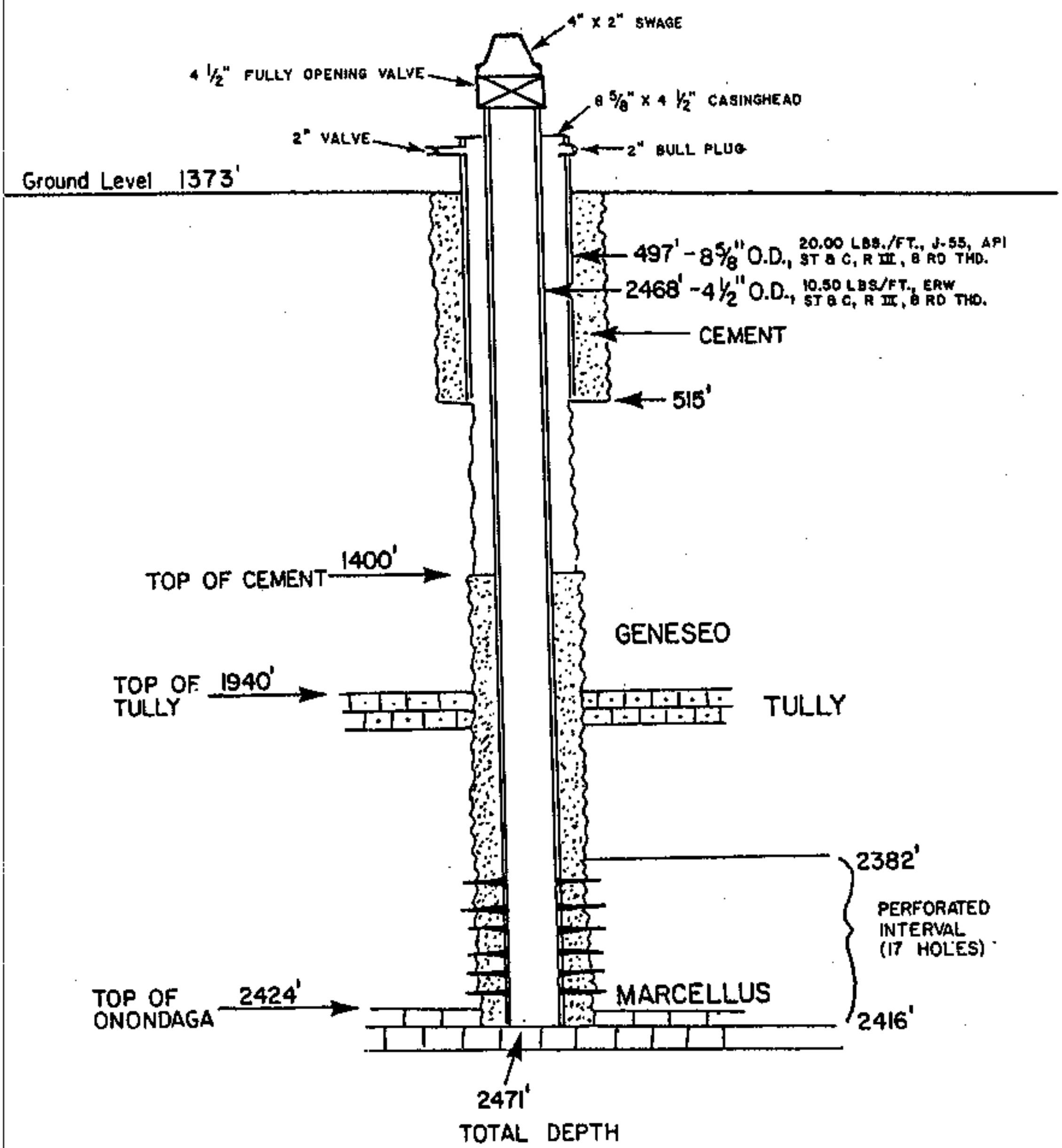
The well was shut-in from April 13th to June 10th (58 days), achieving a fully built-up casing pressure of 627 psig. The well was flowed for a total of 70 hours against 1/8-inch, 3/32-inch, and 1/16-inch chokes. The computed flow rates are shown on Figure A-20. The first four hours of the test were used to blowdown the casing quickly and consisted of a one-hour flow period against the 1/8-inch choke followed by a three-hour flow against the 3/32-inch choke. The remaining 66 hour flow period was through the 1/16-inch choke. The casing pressure at the end of the flow test was 32.5 psia corresponding to a final flow rate of 2.6 MCF/D.

The well was shut-in on June 13th and the pressure build-up monitored for approximately 2,600 hours. On October 29th, the final build-up pressure was 525 psig. Figure A-21 is a log ($Pws^2$-$Pwf^2$) versus log ($\Delta$t) plot indicating that the flow rate was constant up to a shut-in time of approximately 180 hours. Also evident in Figure A-21 is the erratic buildup behavior at approximately 400 hours, 600 hours, and 1,500 hours. This behavior corresponds to drawing down the annulus between the 8 5/8-inch and 4 1/2-inch casing, thus indicating that communication exists between the production casing and the surface conductor pipe set at 515 ft. The Horner buildup plot is shown in Figure A-22. Using the straight line portion of the curve that develops after wellbore storage domination and before the gas in the casing was drawn-down, a permeability thickness product of 0.14 Md-ft was calculated. The calculated values of permeability and skin factor were 4.1 $\mu$D and -2.6, respectively. It is probable that the straight line chosen for the analysis is somewhat steeper than the correct line that would have developed if the annulus had not been evacuated. However, the extrapolated pressure (which corresponds to a surface pressure of 531 psig) was only 6 psi higher than the highest recorded pressure giving some confidence to the reserve projection.

Reserve Estimate

Figure A-23 is a plot of formation pressure divided by deviation factor (P/Z) versus cumulative production. Extrapolating a straight line drawn between the initial pressure and the fully built up pressure from the current test indicates that the initial gas-in-place could have been as low as 1 MMSCF, yielding a remaining reserve of 3.7 MSCF.

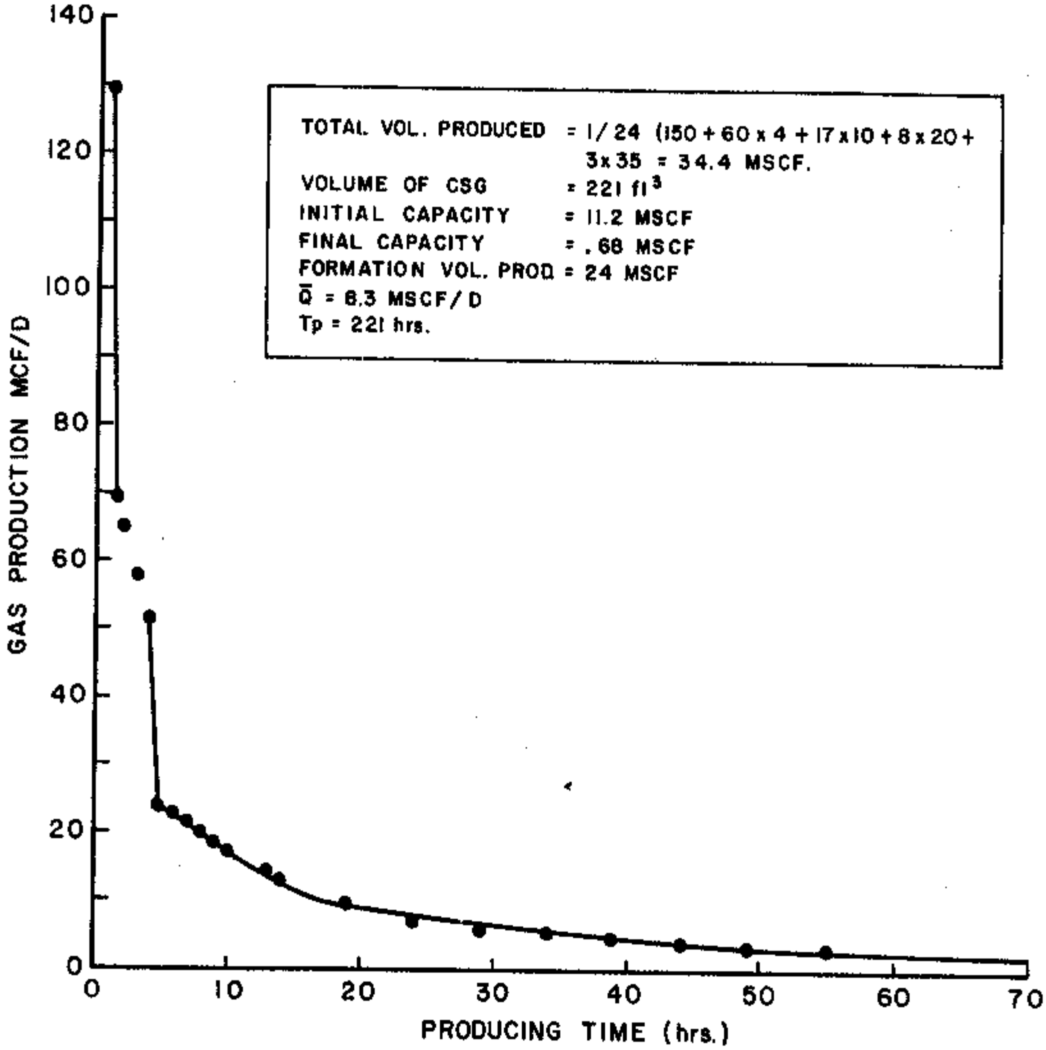
## HOUGHTON COLLEGE #2 WELL




NOTE: All depths are measured from the Kelly Bushing, 4 feet above the Ground Level Elevation.

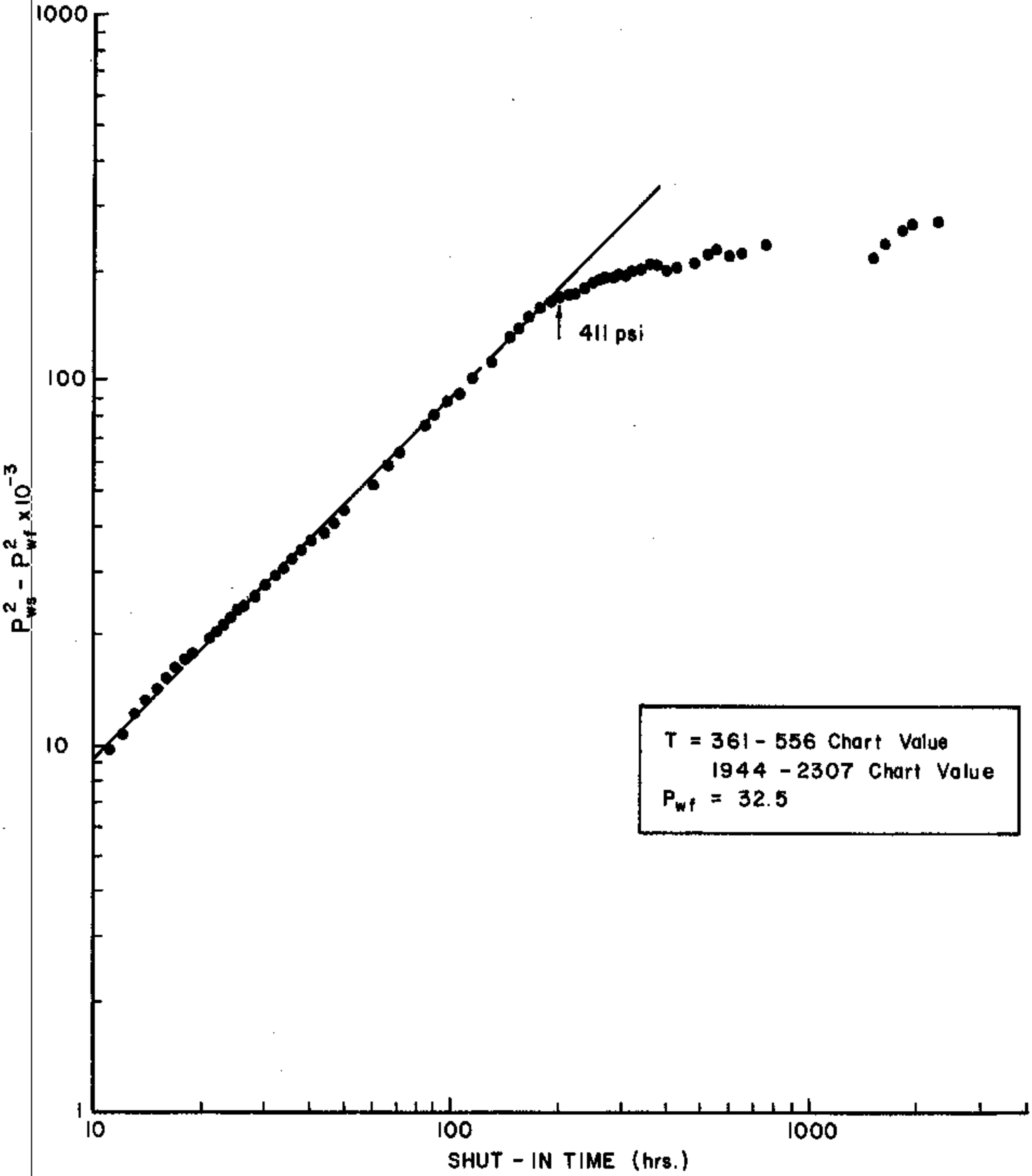
**WELL SCHEMATIC**
**Fig. A-19**

## HOUGHTON COLLEGE #2



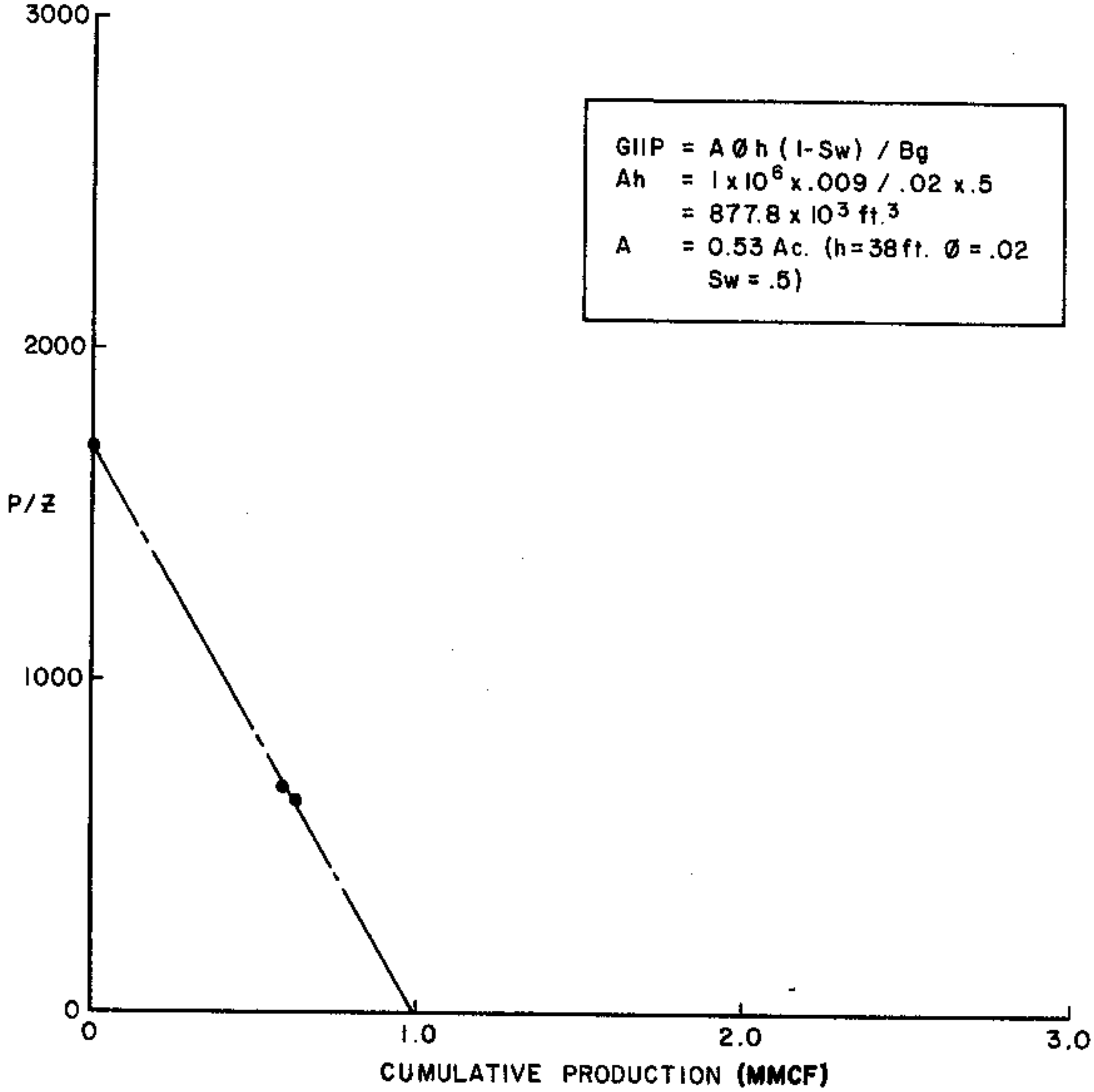

**FLOW PERIOD**
**Fig. A-20**

## HOUGHTON COLLEGE #2




**BUILD UP**
**Fig. A-21**

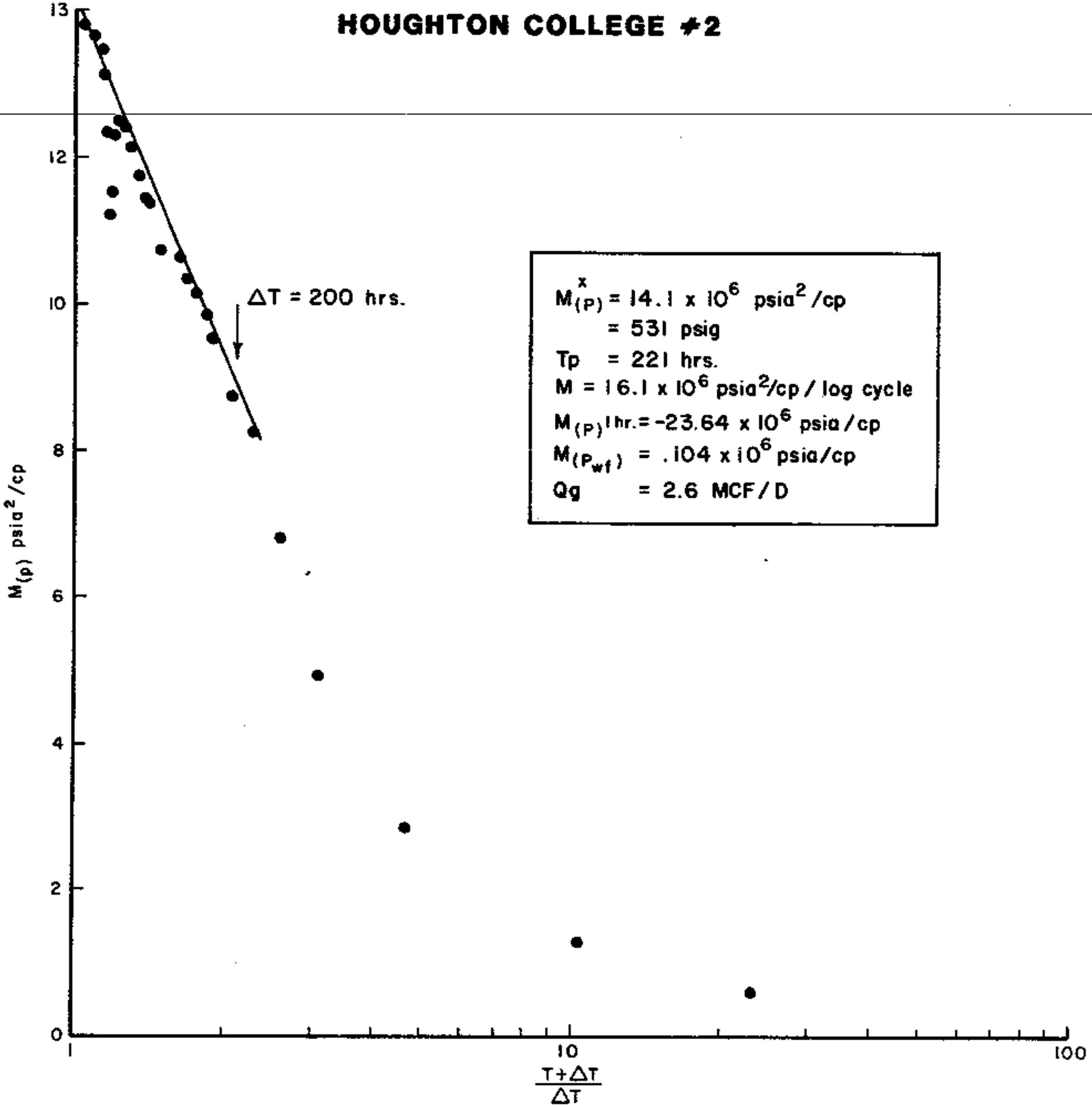
## HOUGHTON #2




**RESERVE ESTIMATE**

**Fig. A-23**

## HOUGHTON COLLEGE #2




**HORNER BUILD UP PLOT**
**Fig. A-22**

ST. BONAVENTURE UNIVERSITY #1 WELL

Introduction

The St. Bonaventure University No. 1 Well, located in Cattaraugus County, New York, was drilled to a total depth of 3,638 feet and completed in the Marcellus shale through perforations of the production casing between 3,602 feet and 3,630 feet. A thinner zone of the shale was also perforated between 3,568 feet and 3,574 feet. In August 1981 the zones were acidized with hydrofluoric acid and fractured using a nitrogen foam carrier. The induced fractures were propped with 10,000 lbs of 80/100 mesh sand followed by 50,000 pounds of 20/40 mesh sand. A well sketch is shown on Figure A-24.

Following the initial swabbing and clean-up, the well was shut-in for approximately six days and recorded a shut-in surface pressure of 1,520 psig.

The well produced periodically for four months between January and December 1982, and had recovered 550 MSCF. The well remained shut-in until the start of the pressure test.

Pressure Test 1983

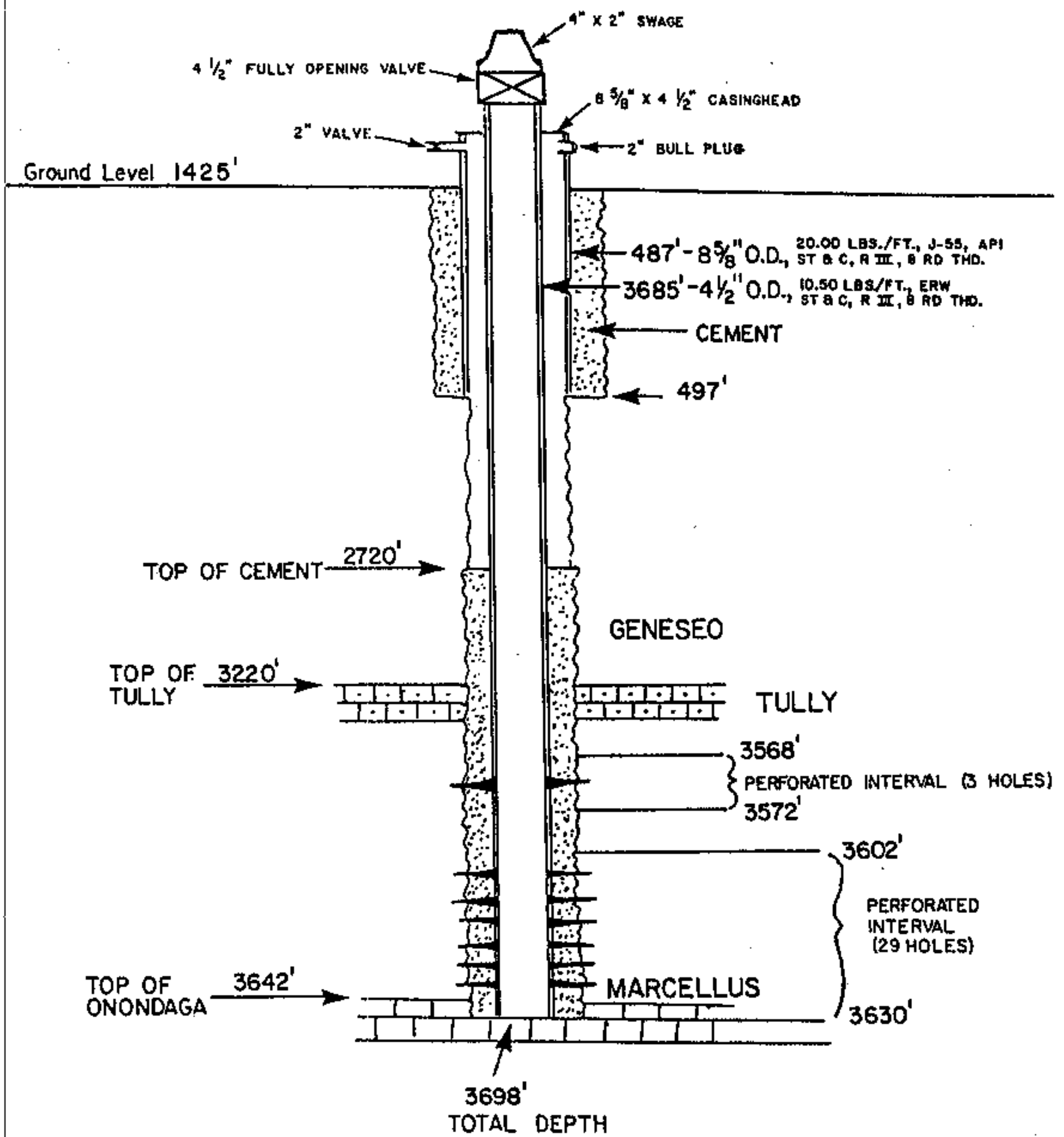
On May 15, 1983 an echometer determined the fluid level to be at a depth of 3,508 feet, 108 feet above the mid point of the lower perforated interval. The casing pressure was 1,424 psig, five and a half months after the last recorded flowing period. The well was opened on May 16th, and flowed against a 1/8-inch choke for 45 minutes, a 1/16-inch choke for nine and one quarter hours, and a 3/32-inch choke for a further thirteen and a half hours. During this initial flow period a combination of low ambient temperatures (around 44°F) and relatively high pressures caused hydrate formation inside the critical flow prover. The well was finally equipped with a 1/16-inch choke on May 17th when a combination of warming temperatures and falling wellhead pressure negated the hydrate problem. The total flowing period was 100 hours. The computed flow rate is shown on Figure A-25 for the 77-hour period where hydrates were not problematic. The final flowing pressure was 67 psig corresponding to a final rate of 6.7 MSCF/D.

The well was shut-in on May 20th, and the pressure buildup monitored continuously for 152 days. The final surface pressure was 1,325 psig. Figure A-26 is a plot of log ($Pws^2$-$Pwf^2$) versus log ($\Delta t$). The initial unit slope portion of the curve persists for 90 hours. The Horner buildup plot is shown on Figure A-27 and revealed no information concerning formation parameters due to changing fluid levels or readsorption of gas onto the shale. In this case, however, due to the presence of a fluid column prior to the test, and the high wellhead pressures, a changing fluid level was more likely.

Reserve Estimate

Using the initial pressure, cumulative production, and the observed pressures during the current test, a reserve estimate was made. Figure A-28 shows a plot of formation pressure divided by deviation factor (P/Z) versus cumulative production. The plot indicates that the initial gas-in-place was between 4.2 and 6.2 MMSCF. Using the higher figure yields a remaining reserve of 5.5 MMSCF.

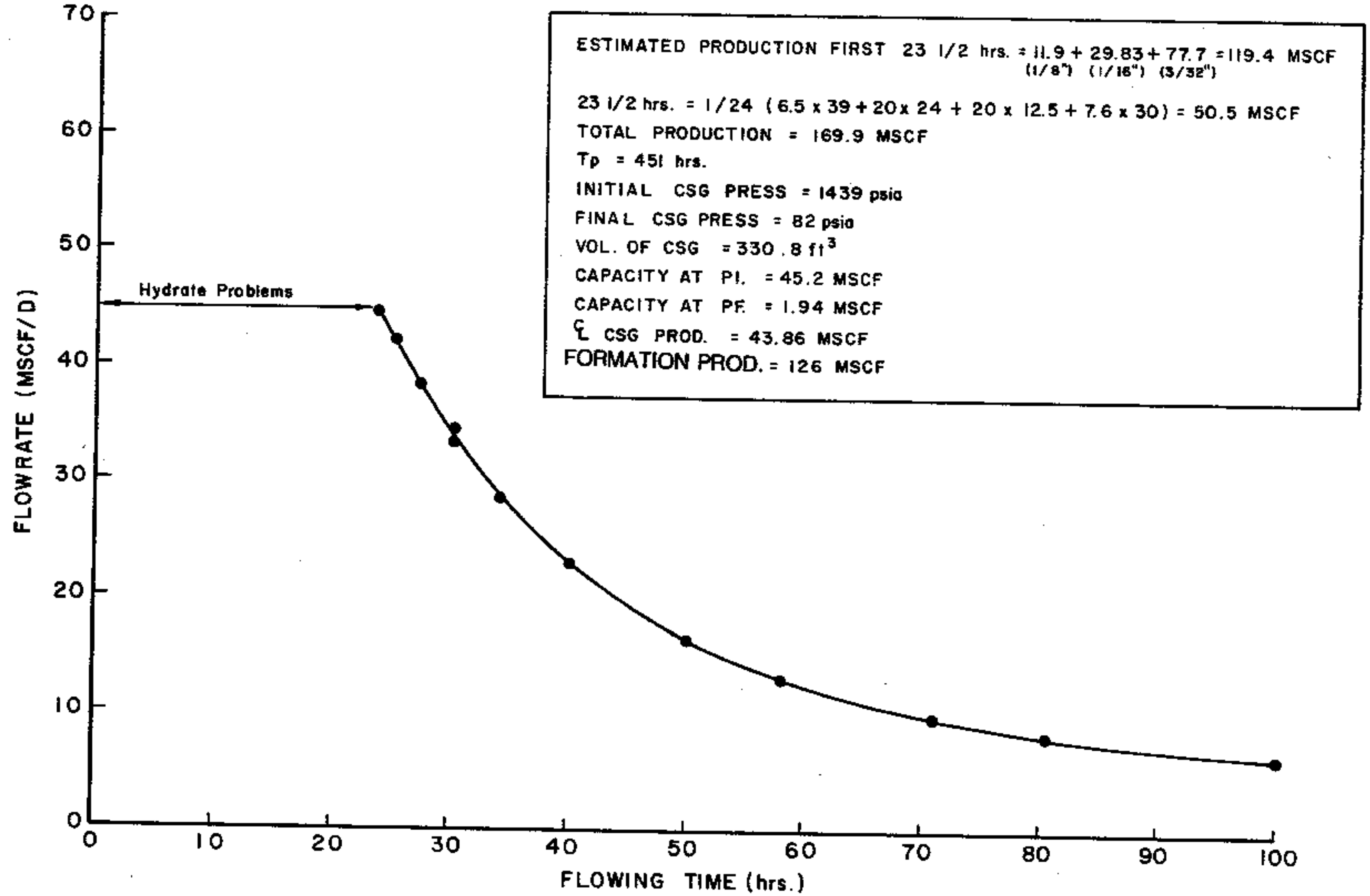
## ST. BONAVENTURE UNIVERSITY#1 WELL




NOTE: All depths are measured from the Kelly Bushing, 10 feet above the Ground Level Elevation.

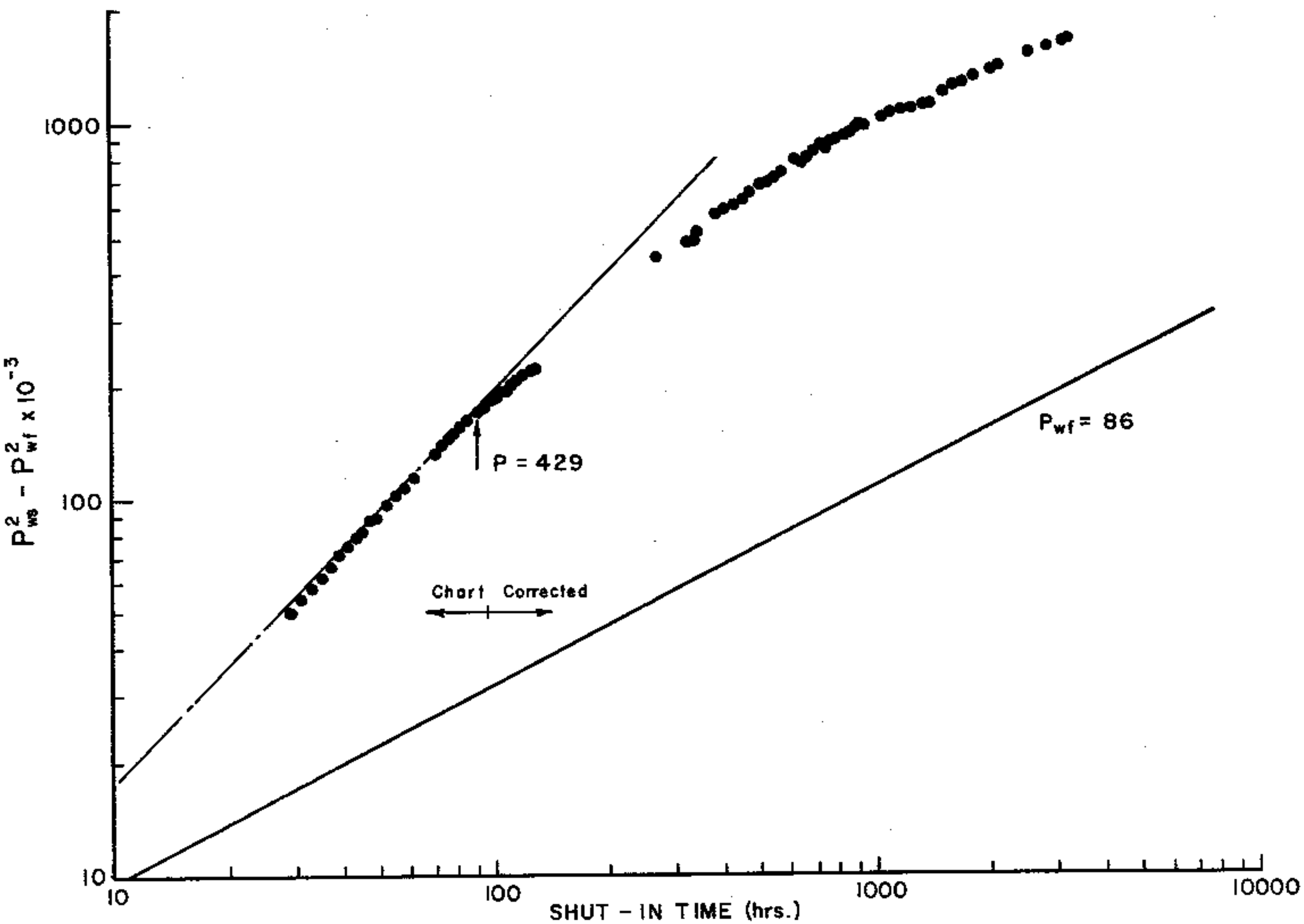
**WELL SCHEMATIC**
**Fig. A-24**

## ST. BONAVENTURE UNIV. #1 WELL




**FLOW PERIOD**
**Fig. A-25**

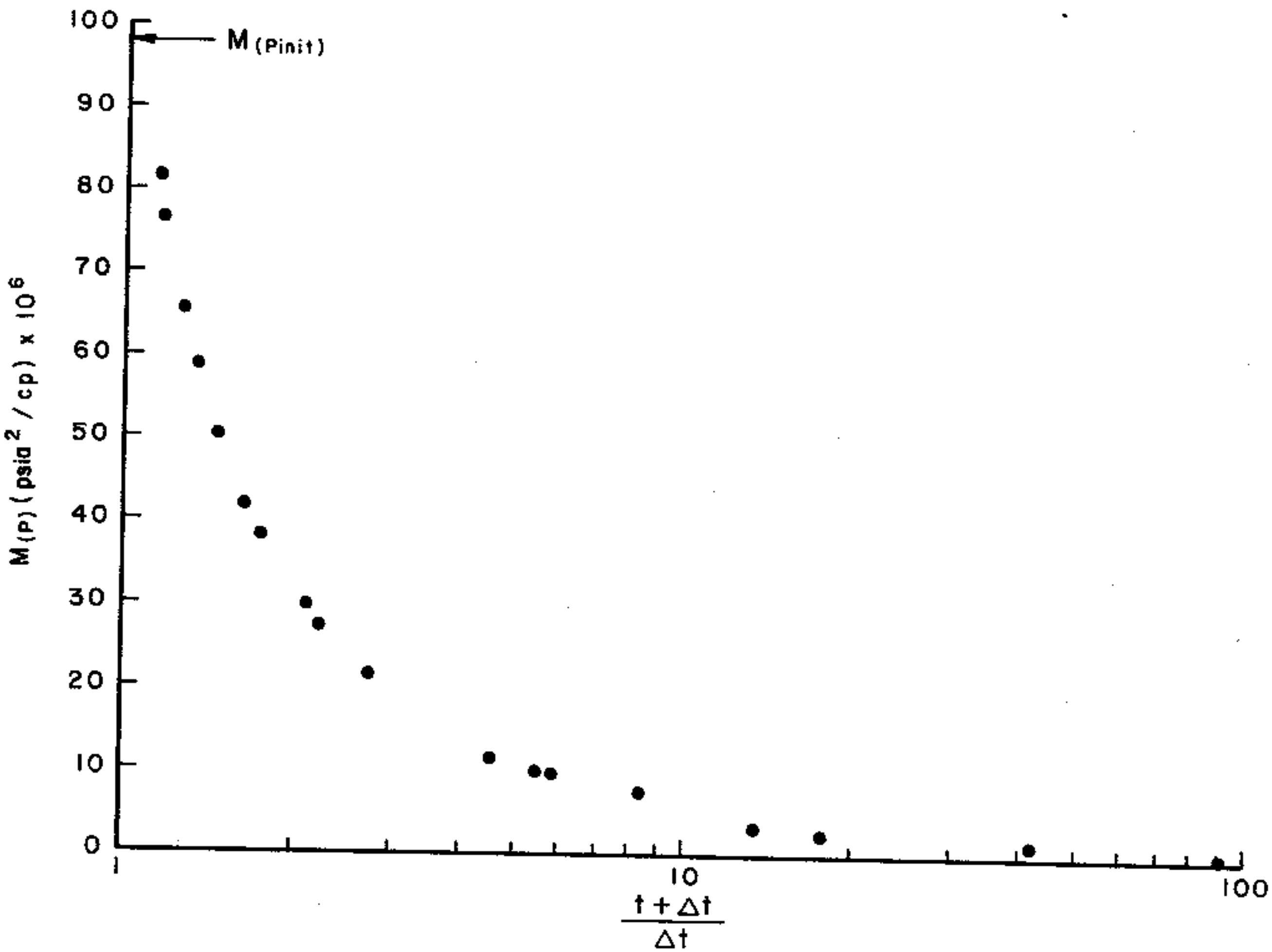
## ST. BONAVENTURE UNIV. #1 WELL




**BUILD UP**

**Fig. A-26**

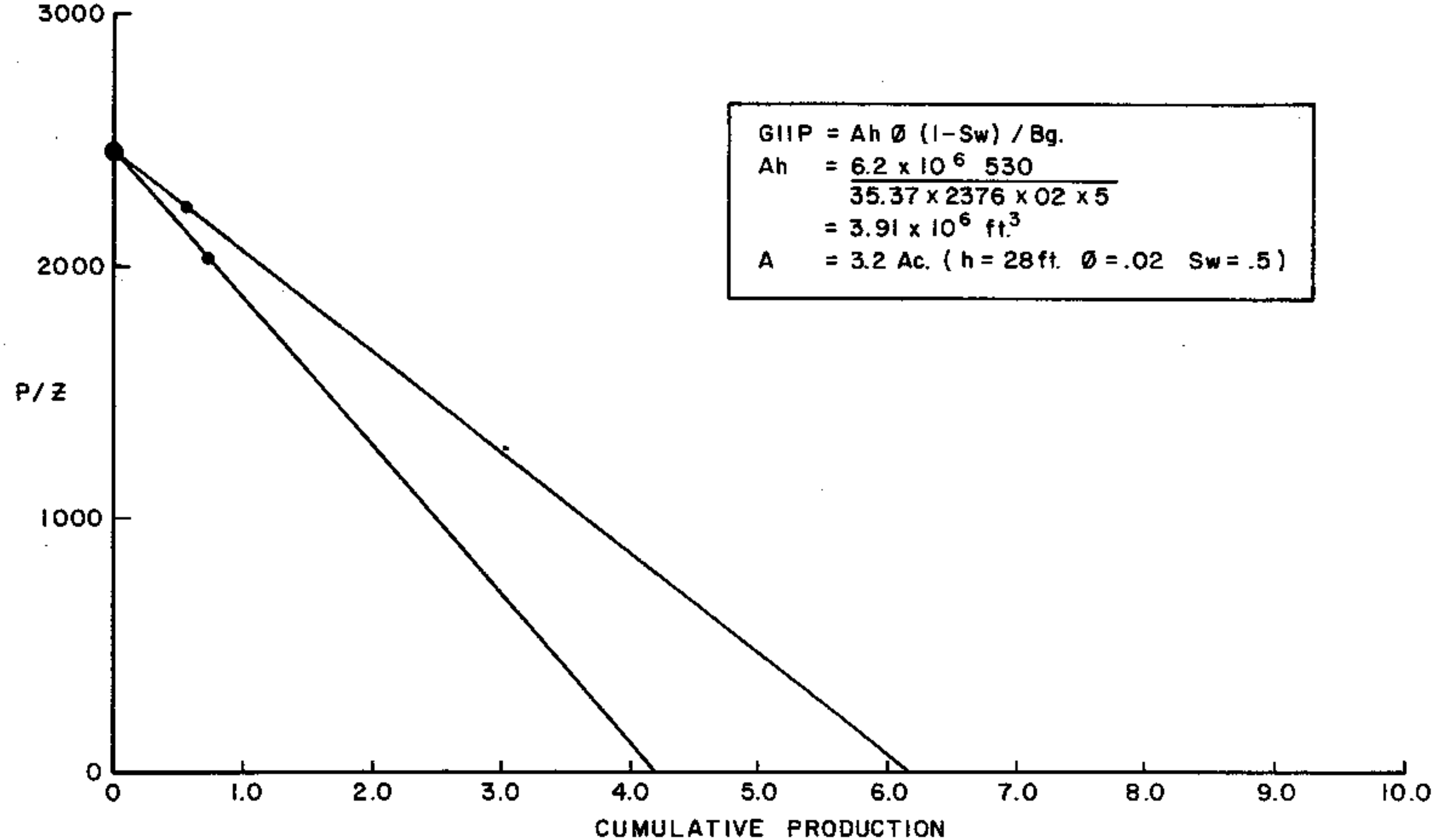
ST. BONAVENTURE UNIV.




HORNER BUILD UP PLOT

Fig. A-27

## ST. BONAVENTURE UNIV. #1 WELL




**RESERVE ESTIMATE**
**Fig. A-28**

## PORTVILLE CENTRAL SCHOOL #1

### Introduction

The Portville Central School No. 1 Well, Cattaraugus County, New York was drilled to a total depth of 4,237 feet and completed in the Marcellus shale with perforations of the production casing between 4,142 feet and 4,176 feet. The well was stimulated in July 1981 using hydrofluoric acid followed by a nitrogen foam fracture treatment. The induced fractures were propped with 10,000 pounds of 80/100 mesh sand followed by 50,000 lbs of 20/40 mesh sand. A well sketch is shown in Figure A-29.

The well was backflowed and swabbed to clean up the fracturing fluid and was shut-in on September 1. A wellhead pressure of 1,820 psig was recorded on September 21, 481 hours after shut-in.

Commercial production began in January 1982 and the well had produced a total of 853 MSCF of gas through the end of February 1983. The well was swabbed in June 1982 at which time fluid was found at 2,176 feet, 2,000 feet (32 bbls) of fluid were removed during the procedure and the wellhead pressure built up to 550 psig in 3 days. The well was shut-in, in April 1983. The wellhead pressure had achieved a stabilized value of 1,010 psig by May 19th.

### Pressure Test 1983

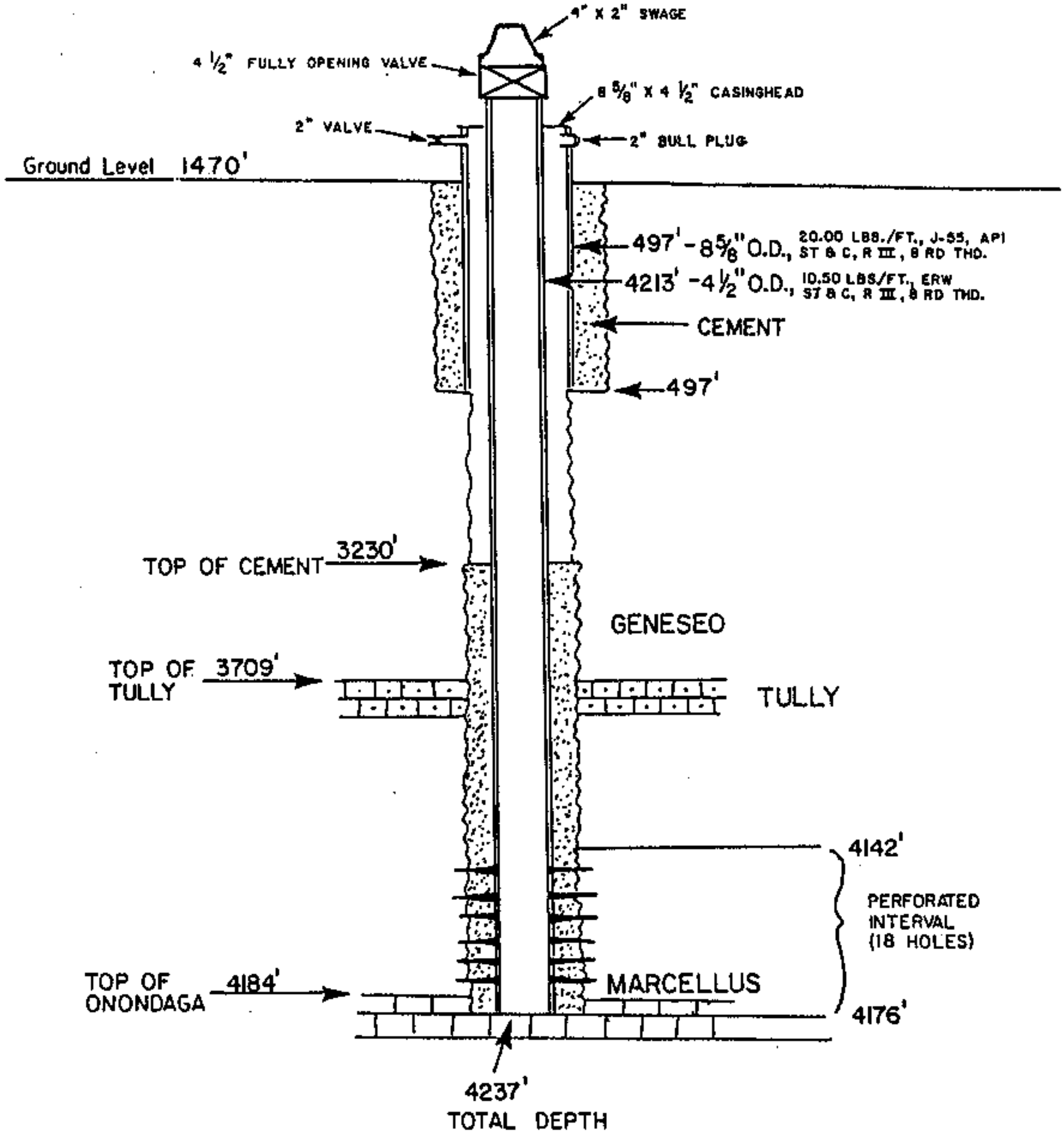
An echometer was run on May 10th and the fluid level was found to be at a depth of 3,053 feet, 1,106 feet above the mid-point of the perforated interval. The well was opened on May 10th and flowed for 92 1/2 hours through a 1/16-inch choke. A plot of the computed flow rate for the flowing period is shown in Figure A-30. The reverse curve during $10 > \Delta t > 35$ hours is believed to be as a result of the choke partially freezing off because of hydrate formation. The estimated total production was 74.5 MSCF with approximately 30% attributed to wellbore storage. The calculated formation contribution was 51.2 MSCF during the flowing period. A final flowing pressure of 51 psig was recorded corresponding to a final flow rate of 5 MSCF/D.

The well was shut-in and the pressure buildup monitored for 206 days, (4950 hours) at which time the surface pressure was 1,132 psig. Figure A-31 is a plot of log ($Pws^2$-$Pwf^2$) versus log $\Delta$ t which indicates that wellbore storage is dominant for the first 180 hours of shut-in time. The Horner plot (Figure A-32) does not reveal any formation information due to changing fluid levels in the wellbore during the shut-in period.

Reserve Estimate

Figure A-33 is a plot of formation pressure divided by the gas deviation factor (P/Z) plotted against cumulative gas production. Two calculated bottom-hole pressures, the inital (1981) pressure and the pressure at the start of the test were used to determine the pressure volume relationship of the reservoir. The extrapolated line indicates that the initial gas-in-place could have been as low as 2.5 MMSCF of gas with a remaining reserve of 1.57 MMSCF.

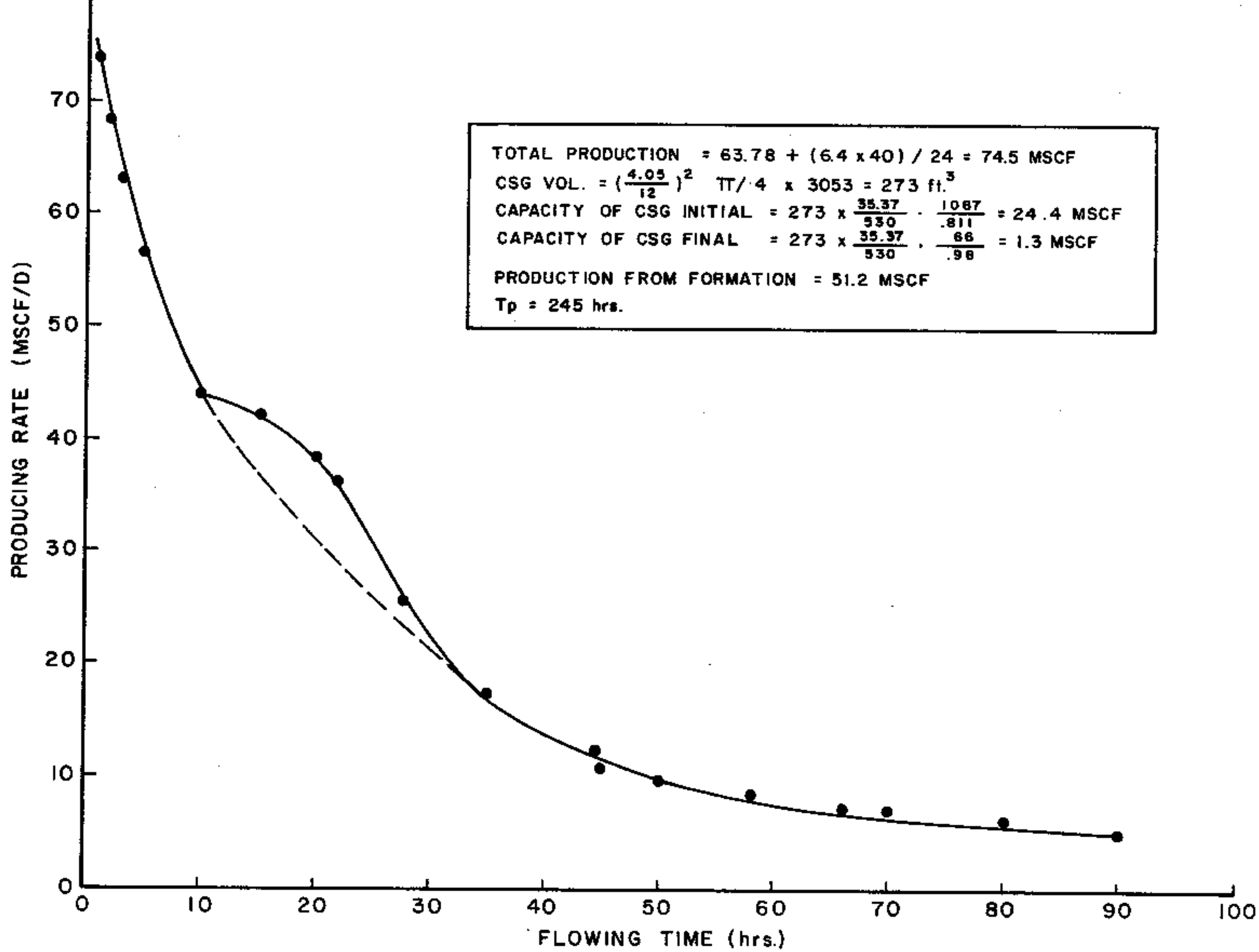
# PORTVILLE CENTRAL SCHOOL
# #1 WELL




NOTE: All depths are measured from the Kelly Bushing, 10 feet above the Ground Level Elevation.

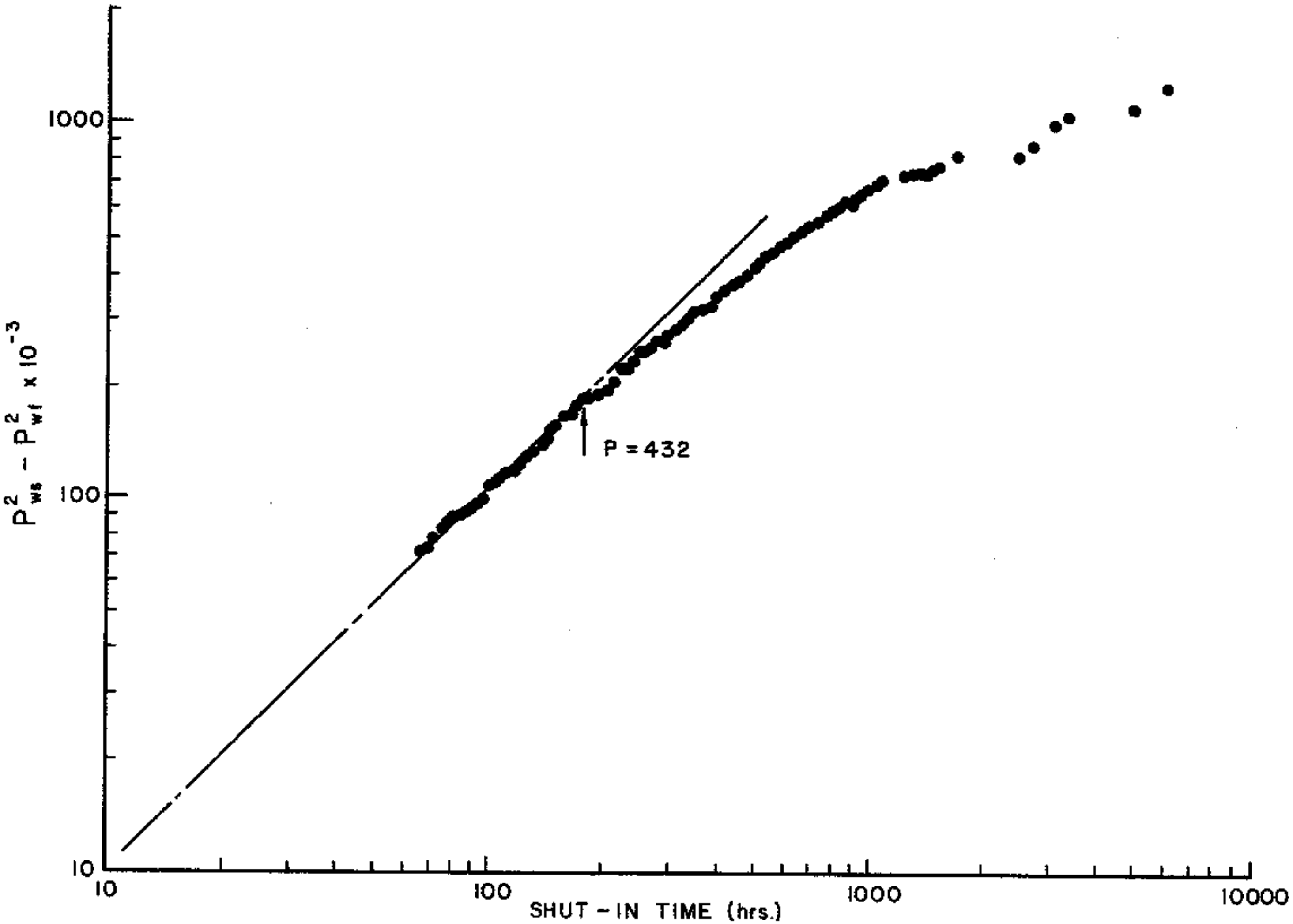
**WELL SCHEMATIC**
**Fig. A-29**

## PORTVILLE CENTRAL SCHOOL #1




**FLOW PERIOD**
**Fig. A-30**

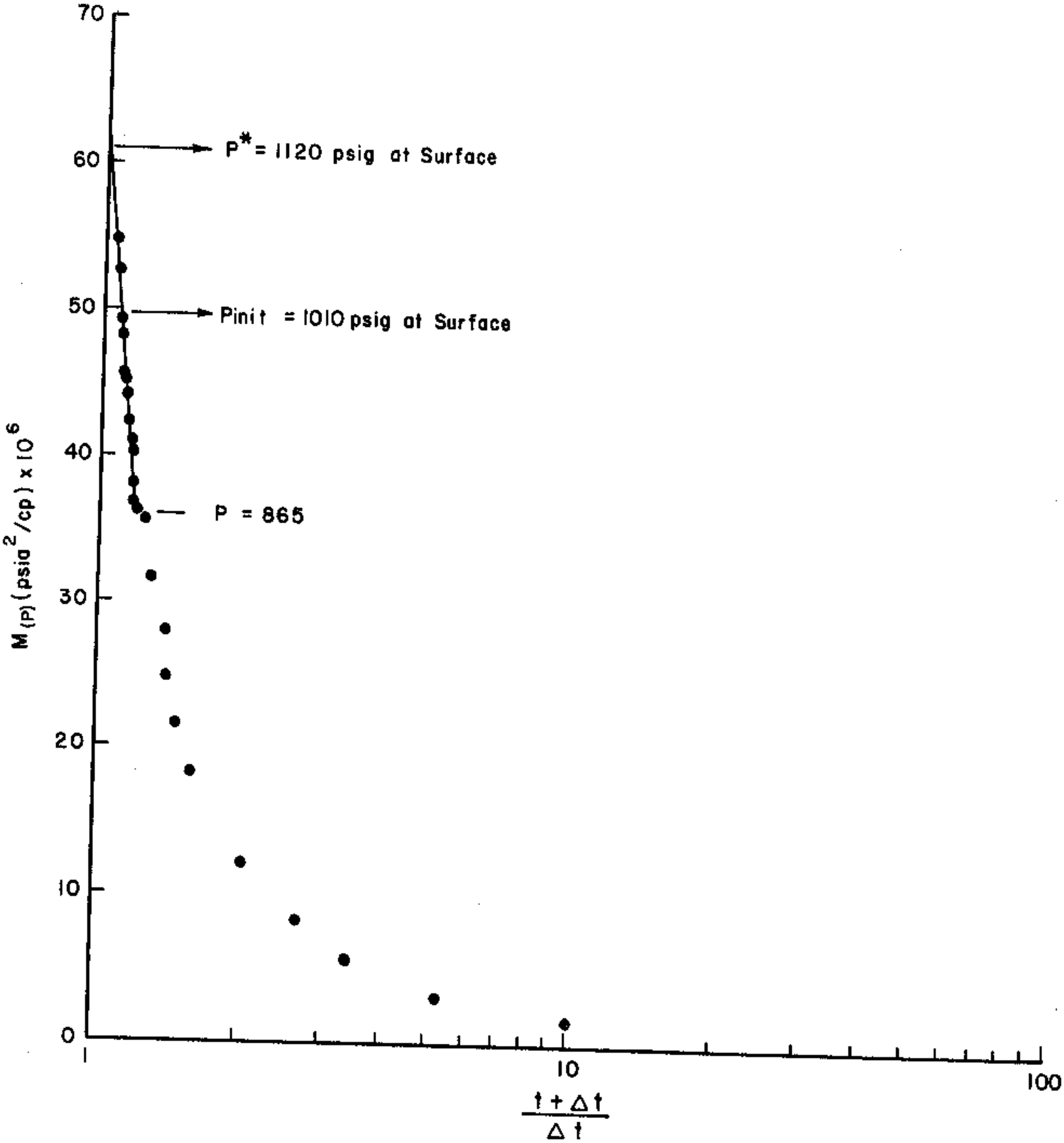
## PORTVILLE CENTRAL SCHOOL #1




**BUILD UP**

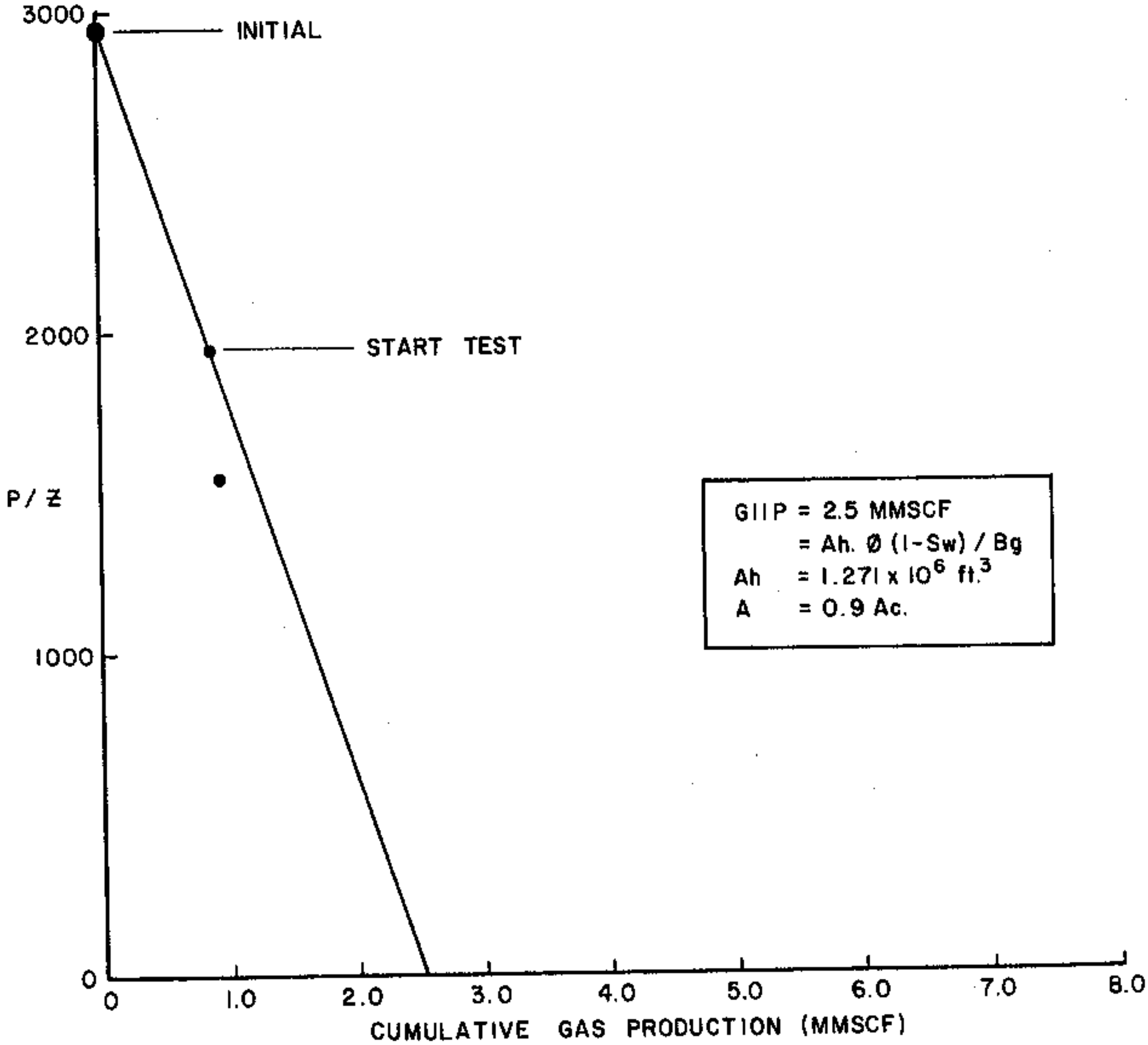
**Fig. A-31**

# PORTVILLE CENTRAL SCHOOL #1




**HORNER BUILD UP PLOT**
**Fig. A-32**

## PORTVILLE CENTRAL SCHOOL #1




**RESERVE ESTIMATE**
**Fig. A-33**

plot (Figure A-37) revealed no formation parameters because of a changing fluid level within the casing string. The final buildup pressure exceeds the initial shut-in pressure by 146 psi and suggests that the fluid level may be 320 feet lower after the 112.5 day shut-in than it was after its initial 56 day shut-in.

## Reserve Estimate

The initial (1981) bottom-hole pressure was calculated, assuming a complete gas column, to be 1,971 psia. An optimistic value of the current bottom-hole pressure was calculated from the extrapolated pressure read from the Horner plot. A pessimistic value of the current bottom-hole pressure was calculated from the highest recorded pressure assuming a complete gas column. The optimistic and pessimistic calculated values were 1,744 psia and 1,500 psia, respectively. Figure A-38 is a plot of formation pressure divided by the deviation factor (P/Z) plotted against cumulative recovery. Optimistic and pessimistic estimates for gas initially in place range from 10.5 MMSCF to 4.6 MMSCF. Remaining reserves were calculated at between 3.4 and 9.2 MMSCF.

ALFRED UNIVERSITY #1 WELL

## Introduction

The Alfred University No. 1 well, located in Allegany County, New York was drilled to a total depth of 3,997 feet and completed in the Marcellus shale through perforations of the production casing between 3,932 feet and 3,970 feet. In July 1981 the well was stimulated using hydrofluoric acid followed by a nitrogen foam fracture treatment. The induced fractures were propped with 10,000 pounds of 80/100 mesh sand followed by 50,000 pounds of 20/40 mesh sand. A well sketch is shown in Figure A-34.

The well was swabbed, flowed for clean-up purposes, and shut-in for two days. At that time (September 20th) a casing pressure of 1720 psig was recorded.

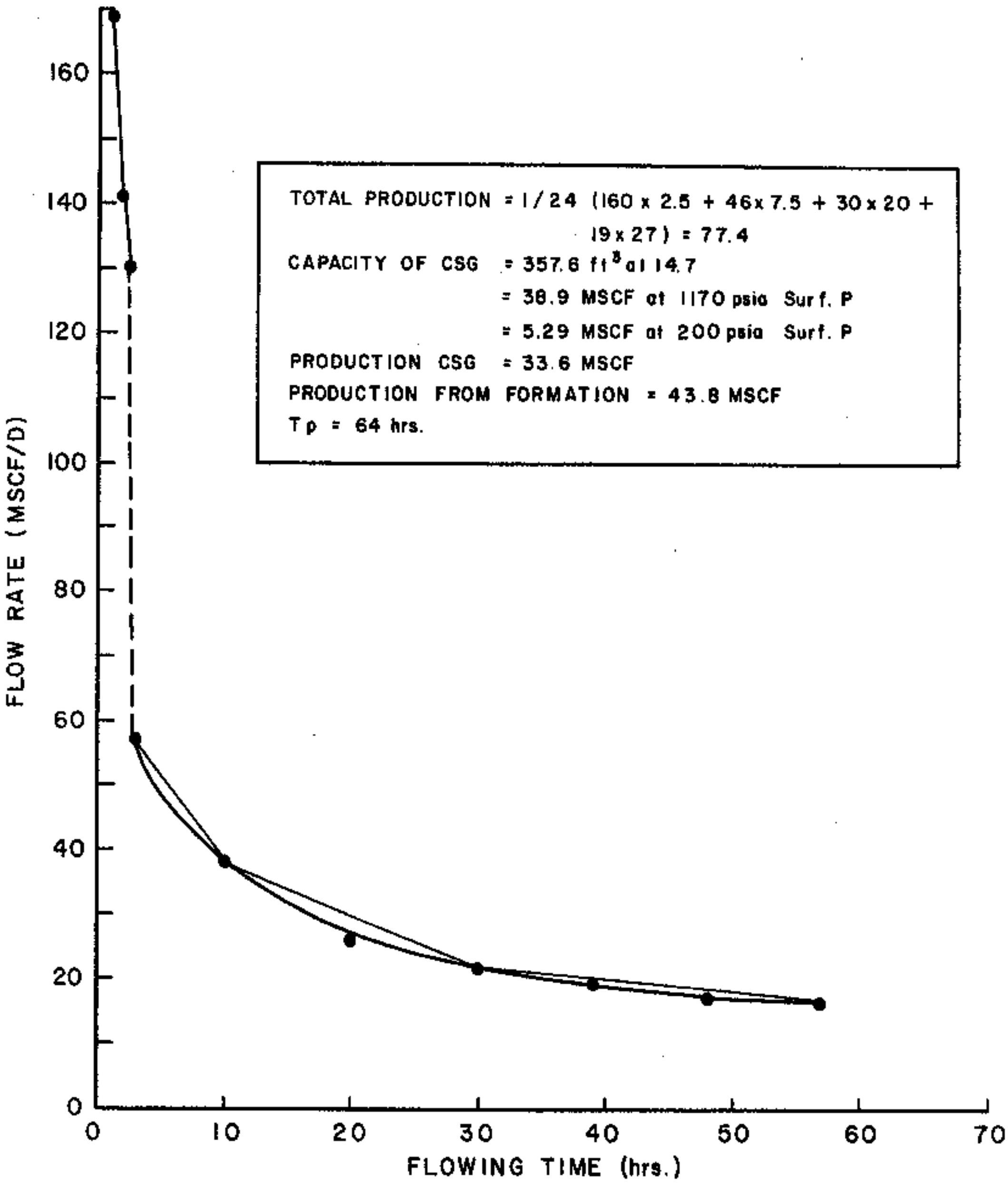
The well was put into service during March 1982 and had produced 1.151 MMSCF to the start of the current test. On November 11, 1982, the well was swabbed to remove wellbore fluids. The well was swabbed again on March 30, 1983, and shut-in for the start of the pressure test procedure.

## Pressure Test 1983

The well was shut-in for 56 days and reached a casing pressure of 1,170 psig. The well was flowed for a total of 57 hours, first through a 3/32-inch choke for 2 1/2 hours followed by a 1/16-inch choke for the remainder of the test. The computed flow rates are shown in Figure A-35. The casing pressure at the end of the flowing period was 185 psig corresponding to a rate of 16 MSCF/D. The total production for the flowing period was estimated at 77.4 MSCF, with the casing contributing 33.6 MSCF, and the formation 43.8 MSCF.

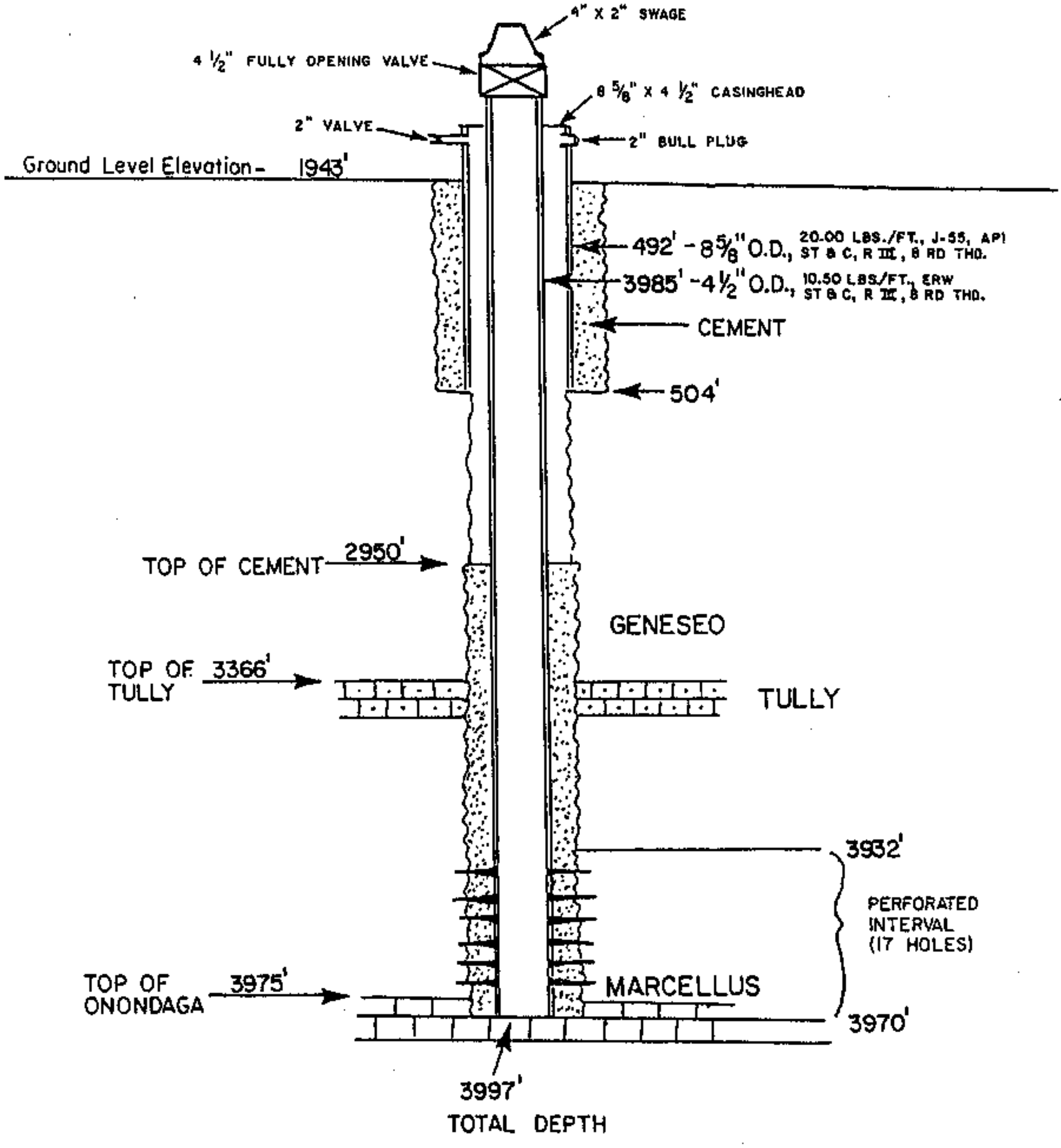
The well was shut-in on May 27th, and the pressure build up was monitored for 2700 hours (112.5 days), on October 17th the final casing pressure was 1,316 psig. Figure A-36 is a plot of log $(Pws^2-Pwf^2)$ versus log $\Delta t$ and indicates that the flow rate was constant for the first 15 hours of the buildup. The Horner buildup

# ALFRED UNIVERSITY #1 WELL




**FLOW PERIOD**
**Fig. A-35**

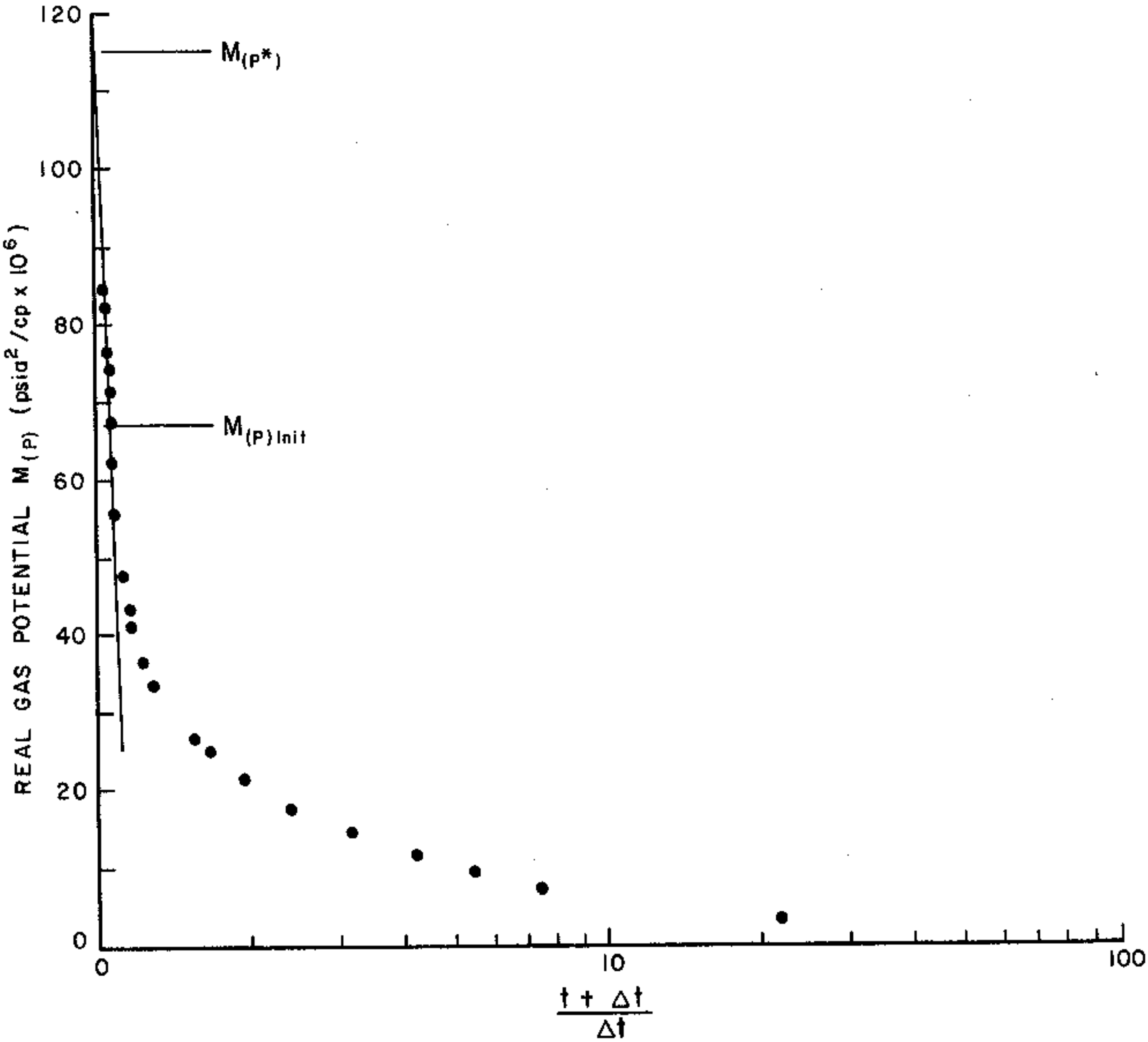
## ALFRED UNIVERSITY #1 WELL




NOTE: All depths are measured from the Kelly Bushing, 10 feet above the Ground Level Elevation.

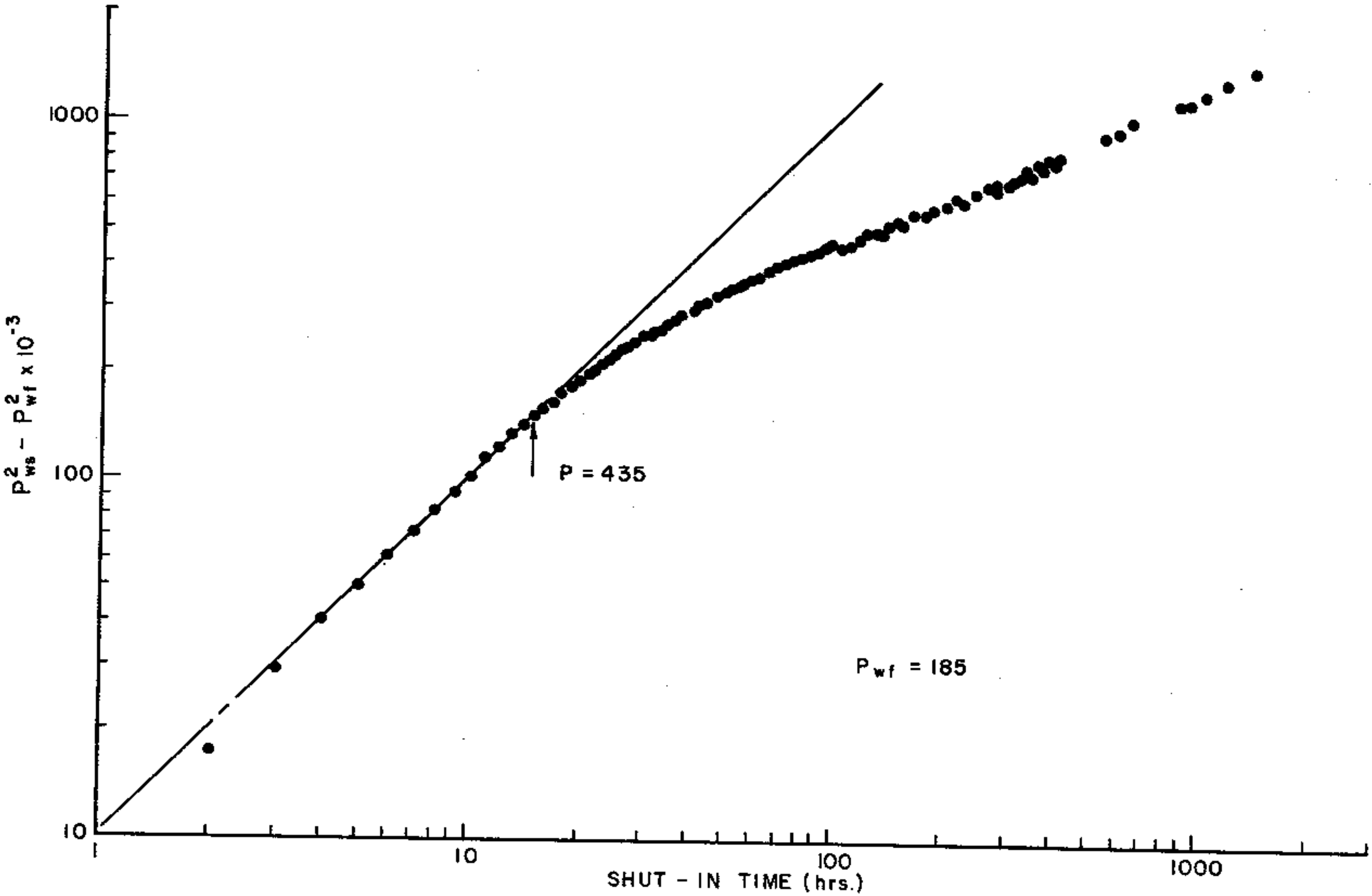
**WELL SCHEMATIC**
**Fig. A-34**

## ALFRED UNIVERSITY WELL #1




**HORNER BUILD UP PLOT**
**Fig. A-37**

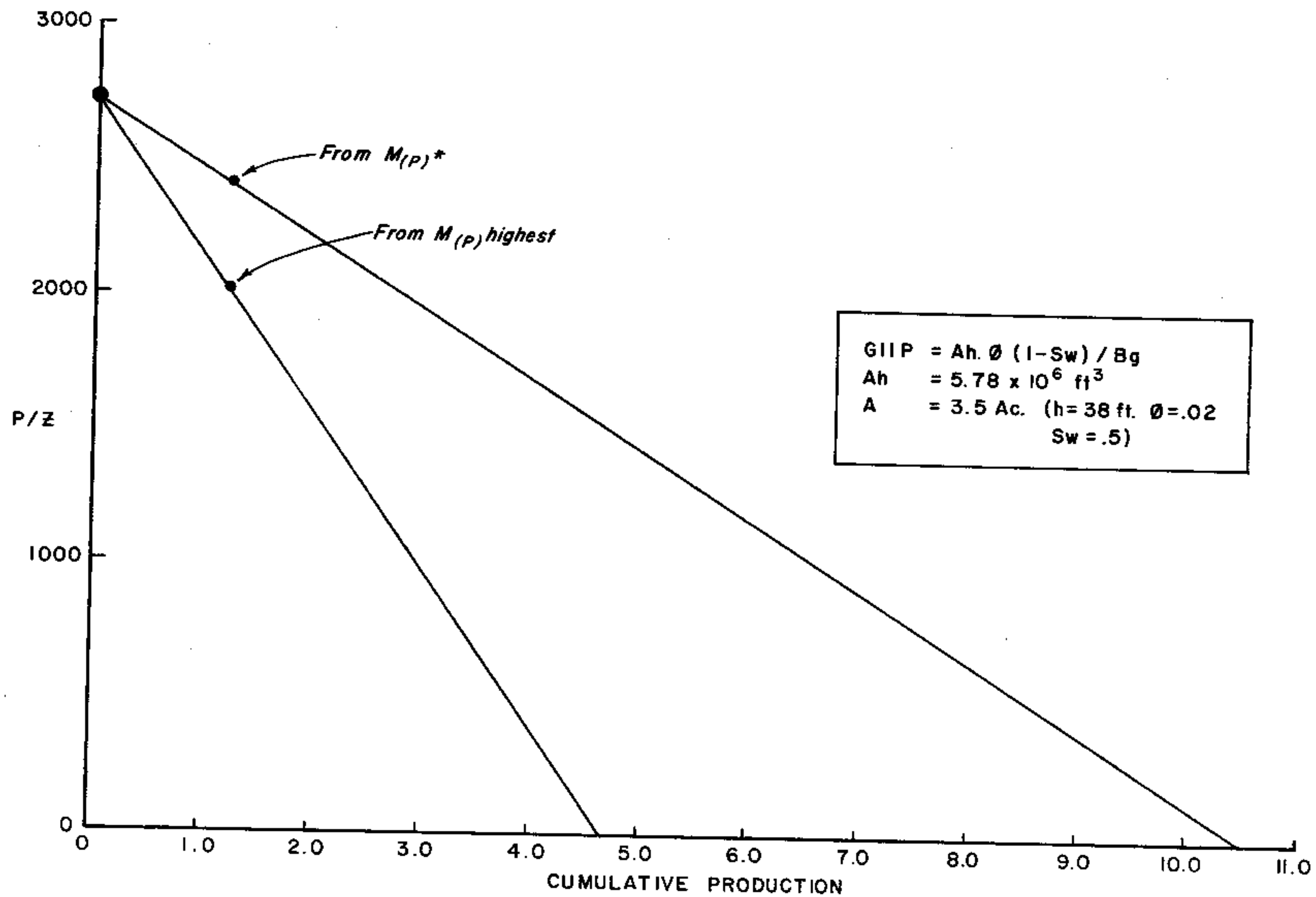
## ALFRED UNIVERSITY #1




**BUILD UP**

**Fig. A-36**

## ALFRED UNIVERSITY WELL #1




**RESERVE ESTIMATE**

**Fig. A-38**

## ALLEGANY COUNTY BOCES #1 WELL

### Introduction

The Allegany County BOCES No. 1 Well located in Allegany County, New York was drilled to a total depth of 3,344 feet and completed in the Marcellus shale through perforations of the production casing between 3,242 feet and 3,282 feet. The well was stimulated using hydrofluoric acid followed by a nitrogen foam fracture treatment. The induced fractures were propped with 10,000 pounds of 80/100 mesh sand followed with 50,000 pounds of 20/40 mesh sand. A well sketch is shown on Figure A-39.

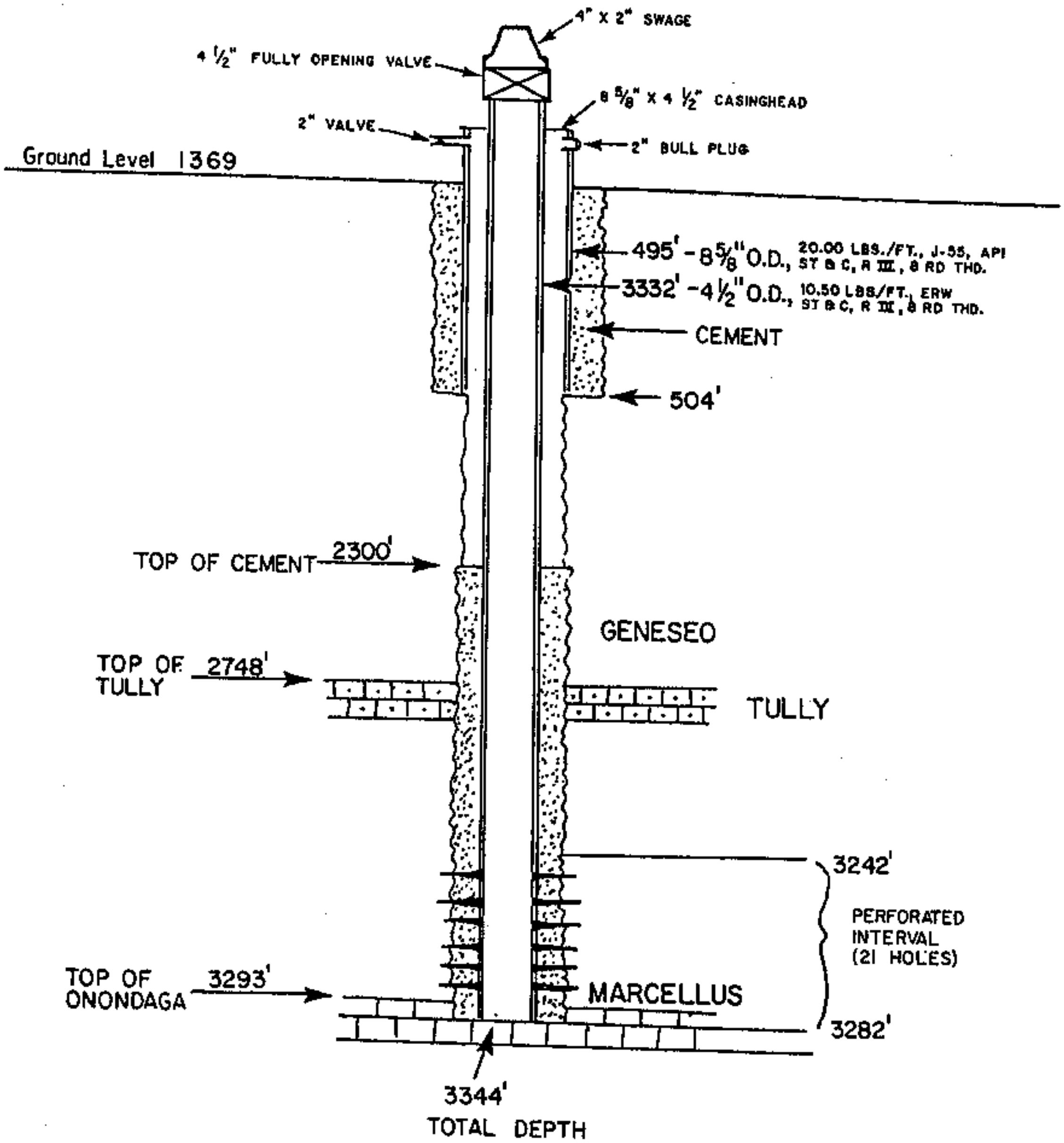
The well was flowed and cleaned up from September 15-18, 1981 and recorded a shut-in wellhead pressure of 1,600 psig after 115 hours.

Production started during December 1981 and the well had produced 2.3 MMSCF through March 22, 1983. The well was blown down and fluid was recovered on April 19, 1983. Thereafter the well remained shut-in until the start of the 1983 pressure survey.

### Pressure Test 1983

The well remained shut-in for 71 days and had achieved a wellhead pressure of 1,341 psig. Pressure continued to build at approximately 2.8 psi/day. Time constraints dictated that the well be put on test. The well was flowed for a total of 147 hours through a 1/8-inch, 3/16-inch, and 1/16-inch chokes. The initial flow using the 1/8-inch and 3/16-inch chokes lasted only 3 hours and was designed to unload the tubing quickly and prevent troublesome hydrate formation. A plot of the computed flow rate versus flowing time is shown in Figure A-40. At the end of the flowing period a surface pressure of 83 psig was recorded corresponding to a flow rate of 7.5 MSCF/D. The calculated total gas production was 139.4 MSCF, with 35.6 MSCF produced from the casing.

## ALLEGANY COUNTY BOCES #1 WELL




NOTE: All depths are measured from the Kelly Bushing, 10 feet above the Ground Level Elevation.

**WELL SCHEMATIC**

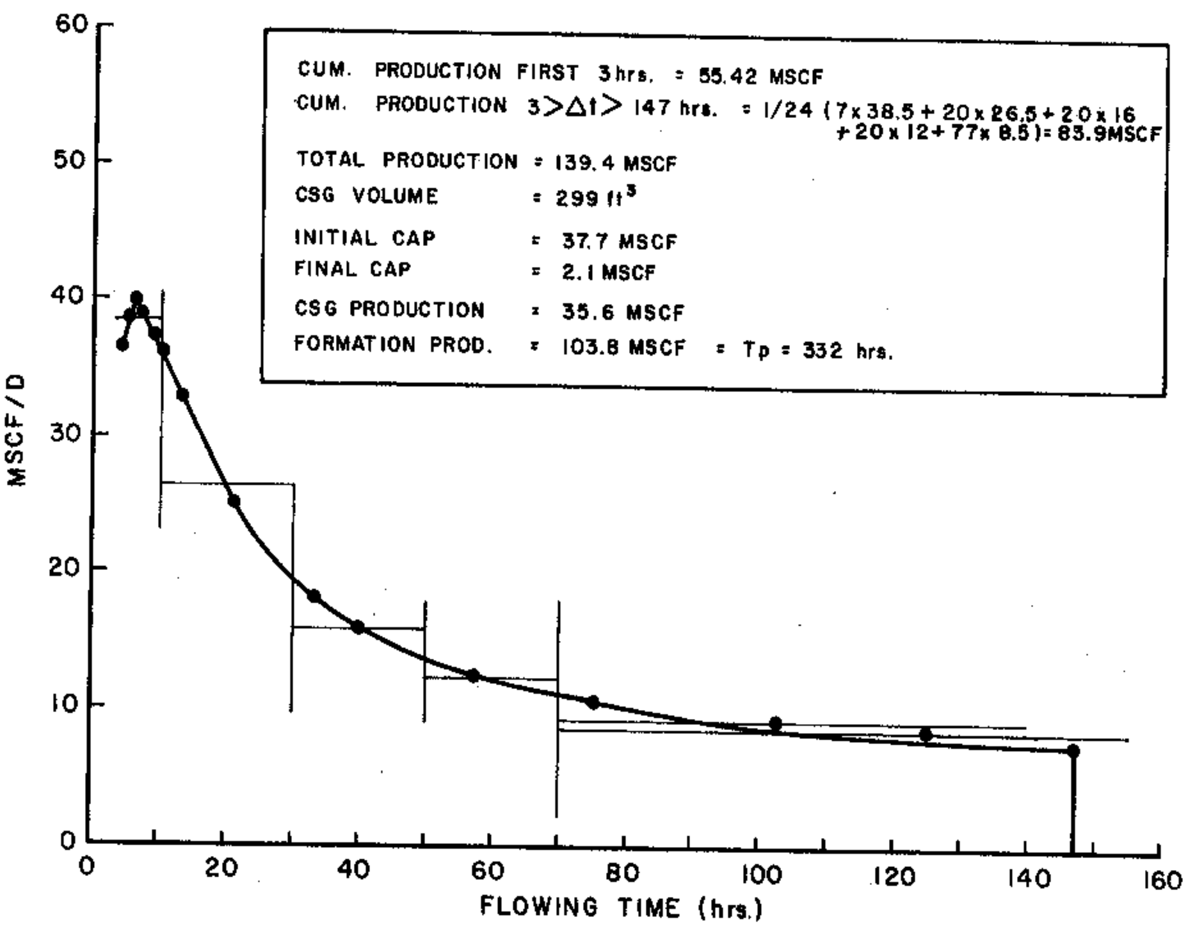
**Fig. A-39**

The well was shut-in on July 5th, and the pressure buildup monitored for 86 days at which time a surface pressure of 1,390 psig was recorded. Figure A-41 is a plot of log ($Pws^2$-$Pwf^2$) versus log $\Delta t$ and shows that wellbore storage is dominant for the first 90 hours of the shut-in period. The Horner plot (Figure A-42) does not reveal any formation information because of changing fluid levels within the wellbore.

## Reserve Estimate

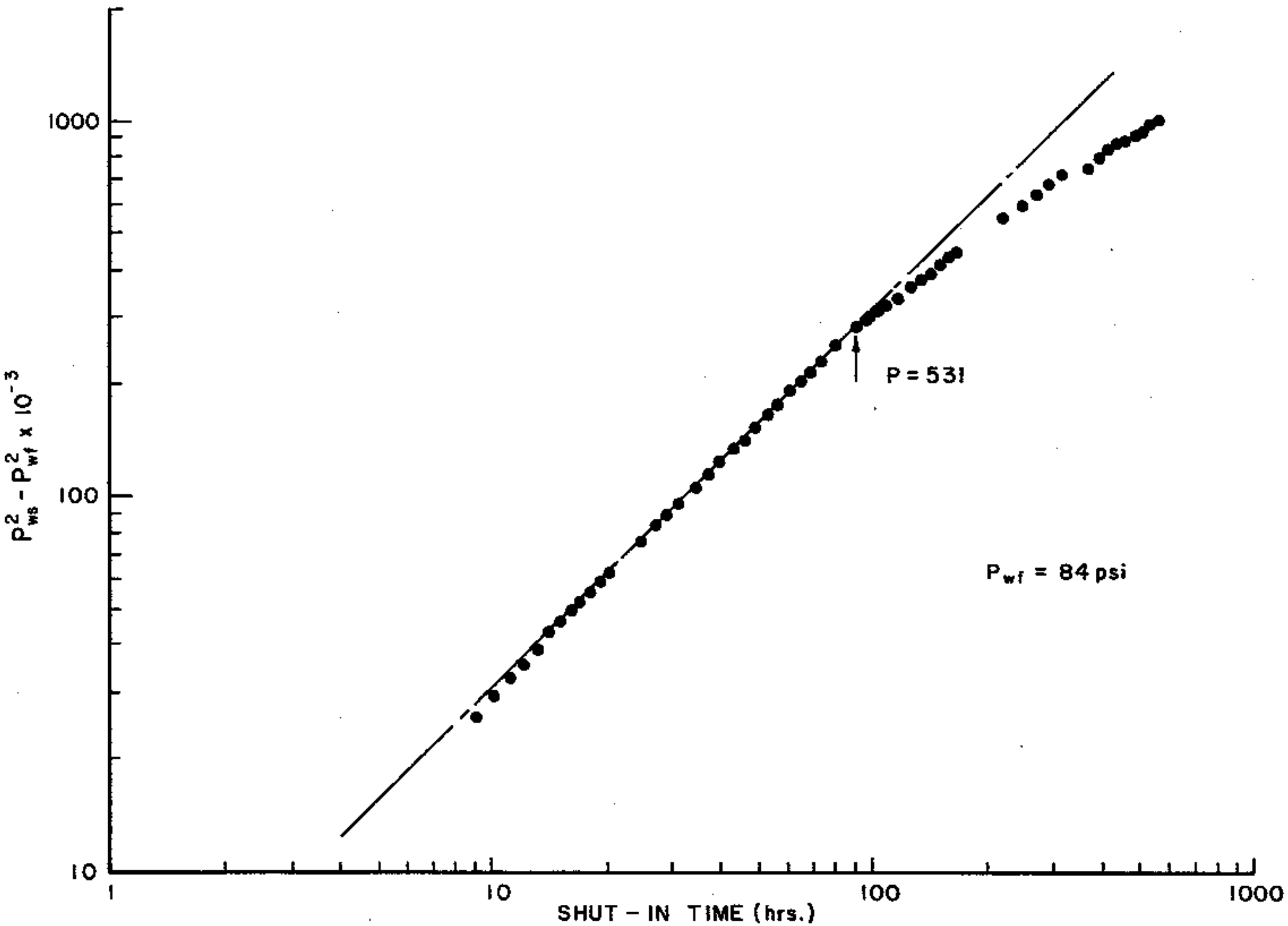
Figure A-43 is a graph of formation pressure divided by the gas deviation factor (P/Z) plotted against cumulative gas production. The initial (1981) pressure and the pressures recorded at the end of the test were used to develop the initial gas-in-place estimate. Using both the highest recorded pressure and the extrapolated pressure from the Horner plot yielded initial gas-in-place estimates of between 14.8 MMSCF and 78.8 MMSCF, respectively. Remaining reserves were estimated to be between 12.36 MMSCF and 76.4 MMSCF. The wide range in the reserve estimate is indicative of the short investigation time used in these tests. Long term production monitoring is required to better establish the reserve definition. A better estimate of reserves cannot be obtained at this time.

## ALLEGANY COUNTY BOCES #1 WELL



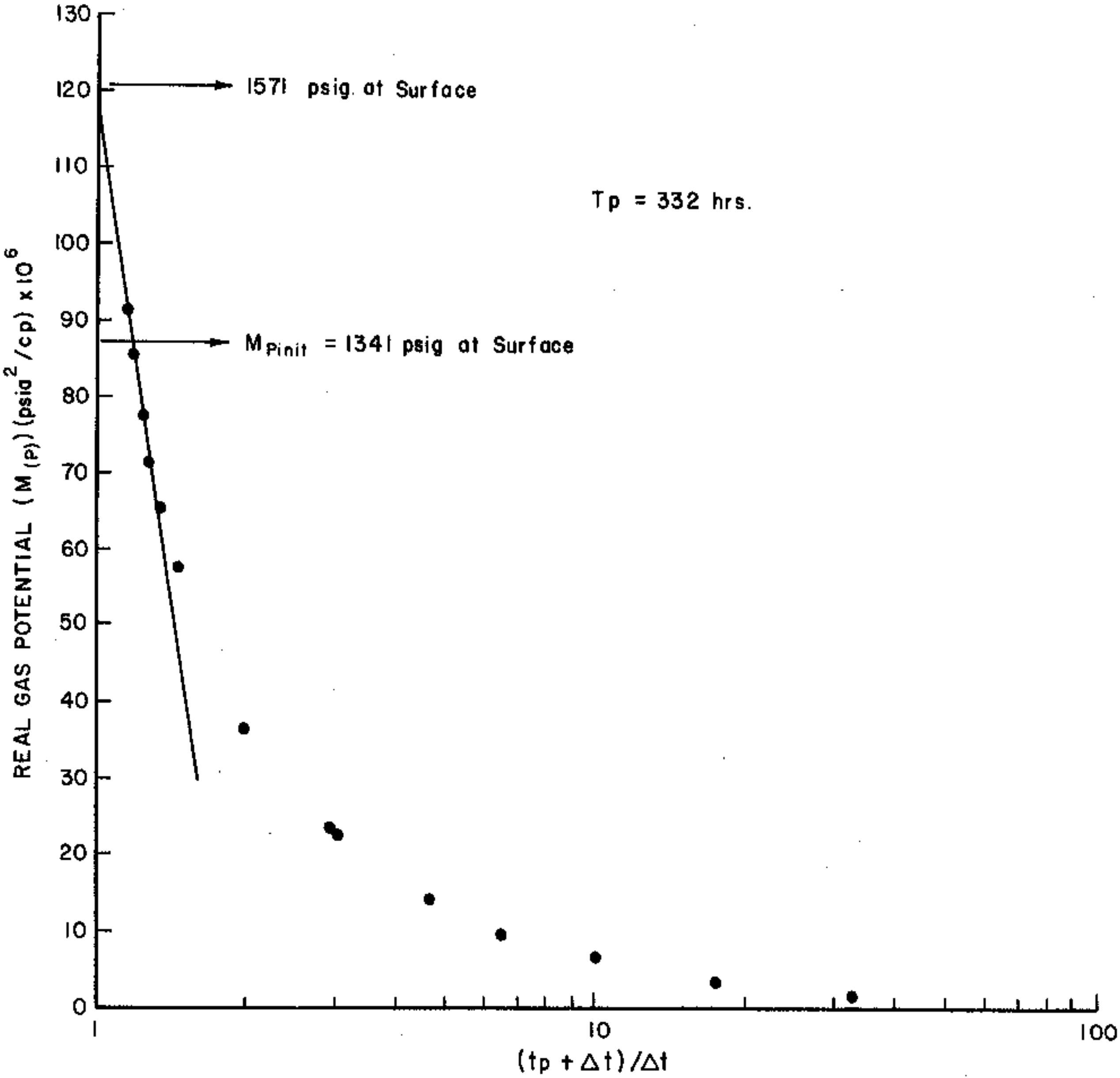

**FLOW PERIOD**
**Fig. A-40**

## ALLEGANY COUNTY BOCES #1 WELL



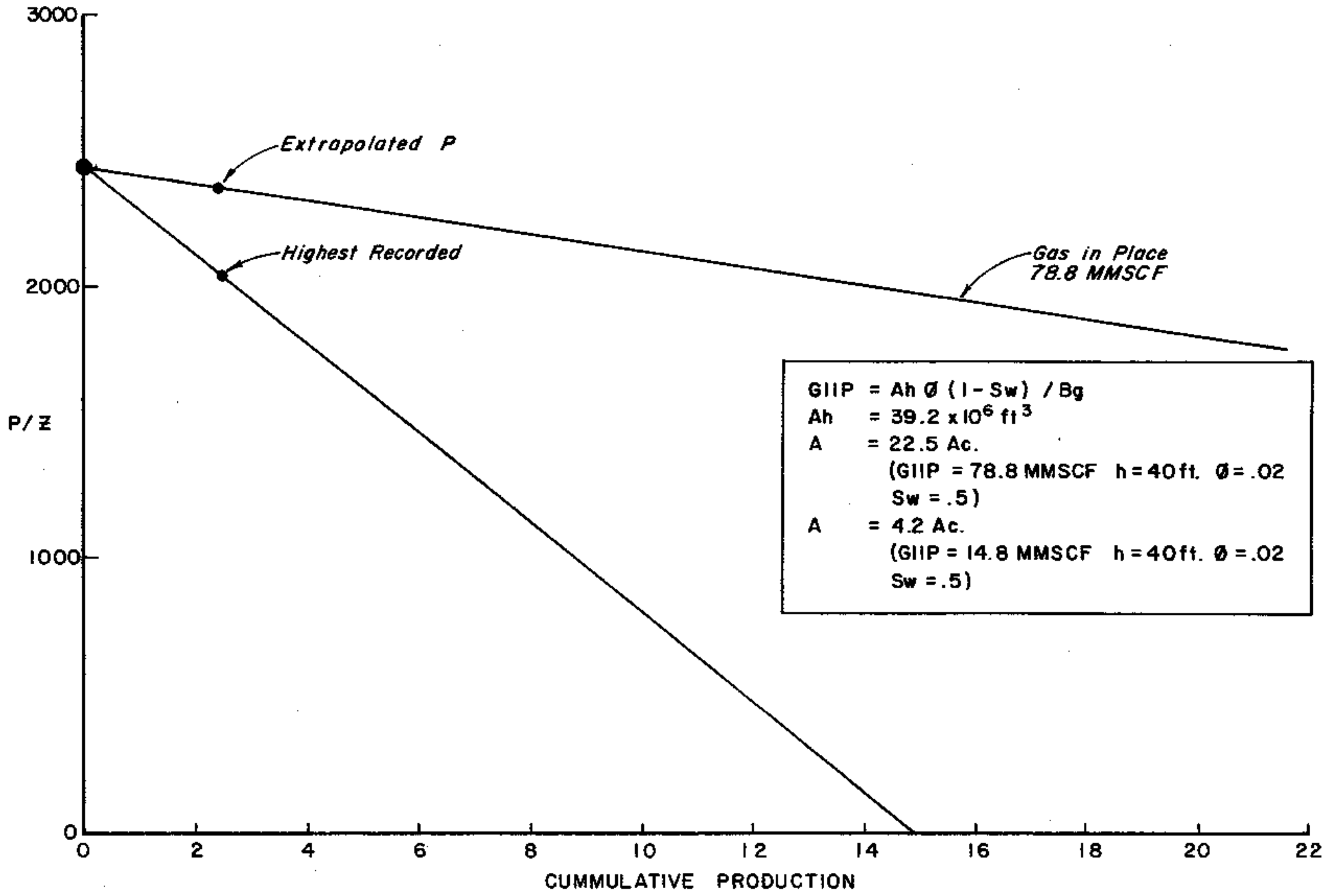

**BUILD UP**
**Fig. A-41**

## ALLEGANY COUNTY BOCES #1 WELL




**HORNER BUILD UP PLOT**
**Fig. A-42**

## ALLEGANY COUNTY BOCES #1 WELL




**RESERVE ESTIMATE**

**Fig. A-43**

## APPENDIX B

## TESTING PROCEDURE FOR DEVONIAN SHALE GAS WELLS (NEW YORK STATE)

### OBJECTIVES

The objective of testing the eight subject wells is to provide a systematic procedure to evaluate their flowing well performance and provide a basis for estimating long-term deliverability and hence reserves. The major problems when testing low deliverability gas wells producing from a fractured (hydraulic and natural) formation is that of separating the various flow regimes as the pressure wave moves out through the formation, and the effects of wellbore storage. A review of the modified isochronal test run in November 1980 revealed that this series of tests had failed to examine the formation due to the overwhelming wellbore storage effects. The test procedure outlined below has been designed to provide a fairly rapid assessment of skin damage and a comparative estimate of prevailing reservoir pressure, which after several tests spread over a period of time will provide good quality data for long-term reserve estimation.

### Valley Vista View No. 1 Well

Specific test procedures were developed for each of the eight subject wells, and follow a similar pattern. The pressure level at which stabilized flow is achieved is a function of the well deliverability and specific pressures can only be calculated when a review of historic tests has been made.

It has been assumed that the wells will have been shut-in for a prolonged period prior to testing. The form of the test is to achieve stabilized flow at two rates followed by a buildup. Inflow performance is matched to choke performance and the casing is blown down to minimize the effects of wellbore storage during the drawdown tests. The final buildup is used to estimate an average pressure.

The wells are equipped with two critical flow provers hooked up in parallel, each with its own gate valve.

- Ensure that a stabilized pressure has been achieved (the pressure should not be increasing more than 2% per week of the prevailing pressure i.e., at 2,150 psig the pressure increase should be less than 6 psi/day).

- Install 1/2-inch choke and 1/16-inch choke in the critical flow provers, open both gate valves, record the time and wellhead pressure, and open the master valve. As the wellhead pressure approaches 1,100 psig* close in the prover with the 1/2-inch choke. The well should stabilize between 1,000-1,100 psig through the 1/16-inch choke at a rate of 82-90 MSCF/D. Allow the well to produce for 48 hours monitoring wellhead pressure every:

- 10 minutes for 1 hour
- 15 minutes between 1 hour-2 hours
- 30 minutes between 2 hours-6 hours
- 1 hour thereafter

These pressures should be taken with an accurate gauge (0-1,500 psig) calibrated against a dead weight tester before and after the survey. A chart recorder will be installed to verify all readings.

- Shut-in master valve and as quickly as possible replace 1/16-inch choke with 1/8-inch choke open both valves to provers, record time and wellhead pressure, open master valve and unload casing to 340 psig (will take approximately 10 minutes to unload casing). Close off the 1/2-inch choke and the well will stabilize at approximately 320 psig at a rate of 105 MSCF/D, allow the well to produce for 48 hours monitoring wellhead pressure every:

- 10 minutes for 1 hour
- 15 minutes between 1 hour-2 hours
- 30 minutes between 2 hours-6 hours
- 1 hour thereafter

---

*Time to achieve stabilization approximately 5 minutes.

These pressures should be taken with an accurate gauge (0-500 psig) calibrated against a dead weight tester before and after the survey. A chart recorder will be installed to verify all readings.

- Shut-in the well and record wellhead pressure following the schedule in step (3). The total shut-in time must be at least 96 hours. Gauges must be available to cover the entire pressure range i.e., 300-2,200 psig.

WORKING NOTES

Analysis of Modified Isochronal Test
Valley Vista View 1

November, 1980

Attachment 1

# Sandface flow Calculations during Shut in Periods

TABLE

EXTEND

| SHUT IN PERIOD | 1 A | 1 B | 1 C | 1 D | 2 A | 2 B | 2 C | 2 D | 3 A | 3 B | 3 C | 3 D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FINAL FLOWING P. | 1700 [1] | 1730 | 1752 | 1772 | 1161 | 1206 | 1242 | 1276 | 247 | 305 | 358 | 404 |
| FINAL SHUTIN P. | 1730 | 1752. | 1772. | 1791. | 1206 | 1242. | 1276 | 1308 | 305 | 358 | 404 | 449. |
| AVERAGE $\bar{Z}$ | | ·785 | | | | ·835 | | | | ·945 | | |
| CSG $V_{OC}$ [2] at | | | | | | | | | | | | |
| INITIAL MSCF | 60·6. | 61·67. | 62·46. | 63·17 | 38·91. | 40·42. | 41·62. | 42·76. | 7·31 | 9·03. | 10·6 | 11·97 |
| FINAL MSCF. | 61·67. | 62·46 | 63·17. | 63·85 | 40·42. | 41·62. | 42·76. | 43·84 | 9·03 | 10·60 | 11·97. | 13·30 |
| $\Delta V$. MSCF | 1·07. | ·79. | ·71. | ·68 | 1·51 | 1·20 | 1·14 | 1·08 | 1·72. | 1·59. | 1·37 | 1·33. |
| $Q_{g_s}$ | 102·7. | 75·84. | 68·16. | 65·2. | 144·9 | 115·2 | 109·4. | 103·6 | 165·0 | 152·6 | 130·8 | 128 |
| $e^s$ | | 1·119. | | | | 1·111 | | | | 1·098. | | |
| $\bar{P}$ | 1715 | 1744 | 1762. | 1782. | 1184 | 1224 | 1259. | 1282 | 276 | 332. | 381 | 427 |
| $P_{sandface}$. | 1918 | 1951. | 1971. | 1993 | 1315 | 1360. | 1399. | 1424 | 303. | 364. | 418. | 469 |
| $\bar{P}^2 \times 10^{+3}$ | 3678 | 3806 | 3885 | 3973. | 1729. | 1850 | 1957 | 2029. | 92. | 133 | 175 | 219. |
| $P_{res}^2 - \bar{P}^2 \times 10^3$ | 2180. | 2052. | 1973. | 1885 | 4129. | 4008 | 3901. | 3829 | 5766. | 5725 | 5683. | 5639. |

(1) error according to chart.

(2) Physical size = 431·8 ft$^3$ Vol calculated from $\left(V_{520}/15·43 \times Z\right)(\bar{P})$.

$P_{rs}$ = 2159. 1.12. = 2420 $P_{res}^2$ = 5858.

Tubing performance Curves for various Choke sizes TABLE(2)

$$Q = C\left[\left(\frac{1}{\gamma_g T}\right)^{0.5}\right] \cdot P = C\left[\cdot 053\right] P.$$

| Choke Size. $A \times 10^{-3}$ | | C (2 in Prover) | Q MSCF/D. P 100 | 400 | 700 | 1000 | 1500 |
|---|---|---|---|---|---|---|---|
| 1/16 | 3.068 | 1.524 | 8.11 | 32.4. | 56.77. | 81.1. | 122 |
| 3/32 | 6.903. | 3.355 | 17.8. | 71.4. | 125 | 178 | |
| 1/8 | 12.27 | 6.301. | 33.5 | 134 | 235 | 335 | |
| 3/16 | 27.61 | 14.47. | 77 | 308 | 539 | 770. | |
| 7/32 | 37.58 | 19.97 | 106.3 | 425 | | | |

in excess of AOFP.

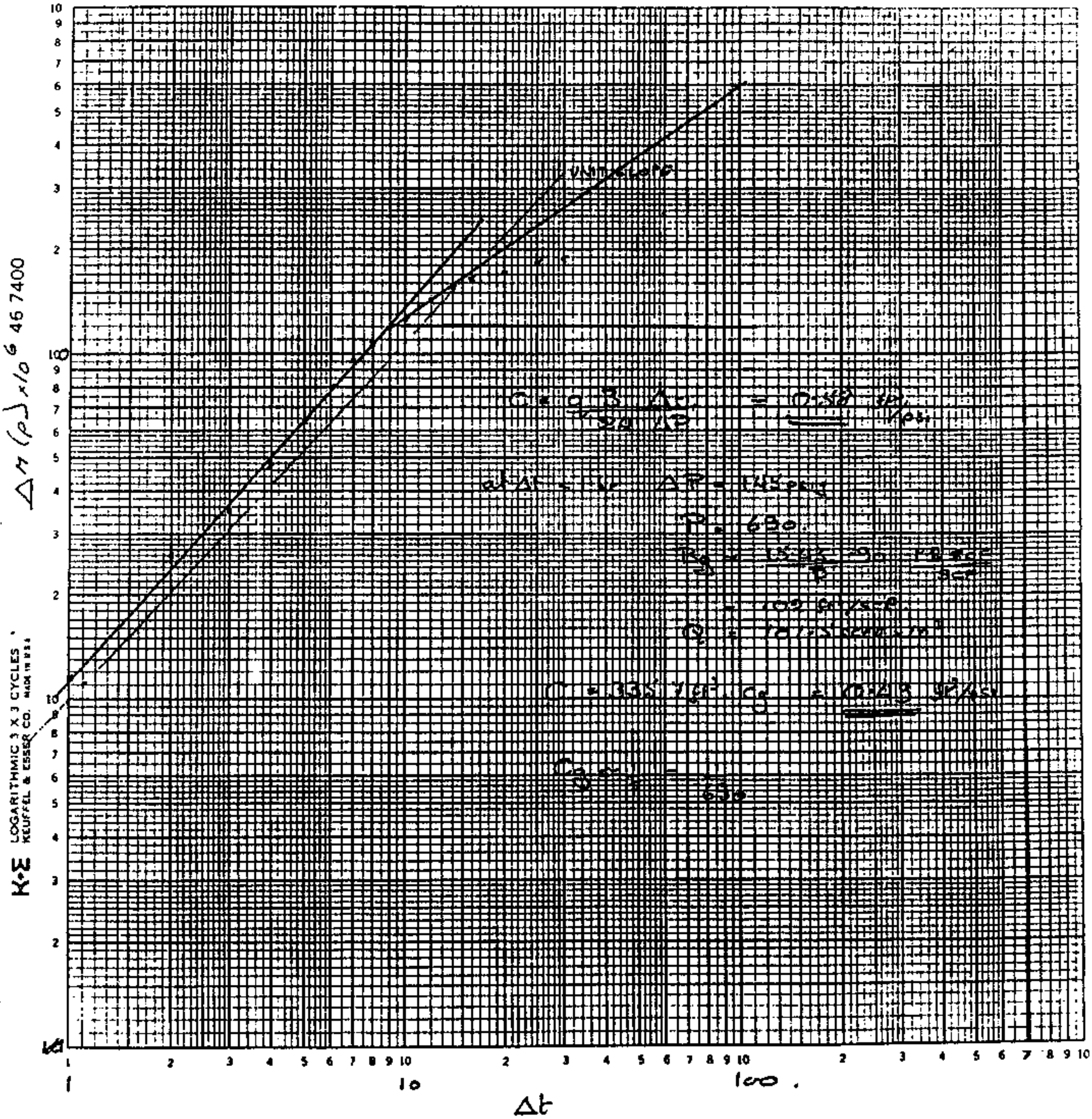
| $P_{surf}$ | Z | $S^{(1)}$ | $e^{S}$ | $P_{bh}$. | $P_{bh}^2 \times 10^3$ | $\Delta P^2$ (pinit. 215 |
|---|---|---|---|---|---|---|
| 100 | .99. | .089 | 1.093. | 109.3. | 11.95 | 5830. |
| 400 | .94 | .094 | 1.099 | 439. | 192.7 | 5649. |
| 700 | .895 | .098 | 1.103 | 772. | 595.9 | 5246 |
| 1000. | .85 | .103 | 1.109. | 1109. | 1229.9. | 4612. |
| 2156 | .77 | .114 | 1.121 | 2417 | 5842.0 | – |
| 1500 | .80 | .110 | 1.116. | 1674 | 2803.6 | 3038. |

$S = (\gamma_g \cdot L) / (53.3\, T \cdot Z) = .088/Z$

from $Q = 7.05 \times 10^{-3} \cdot \left[(\Delta P)^2\right]^{.62}$. (n=1) $(c = 1.855 \times 10^{-2})$

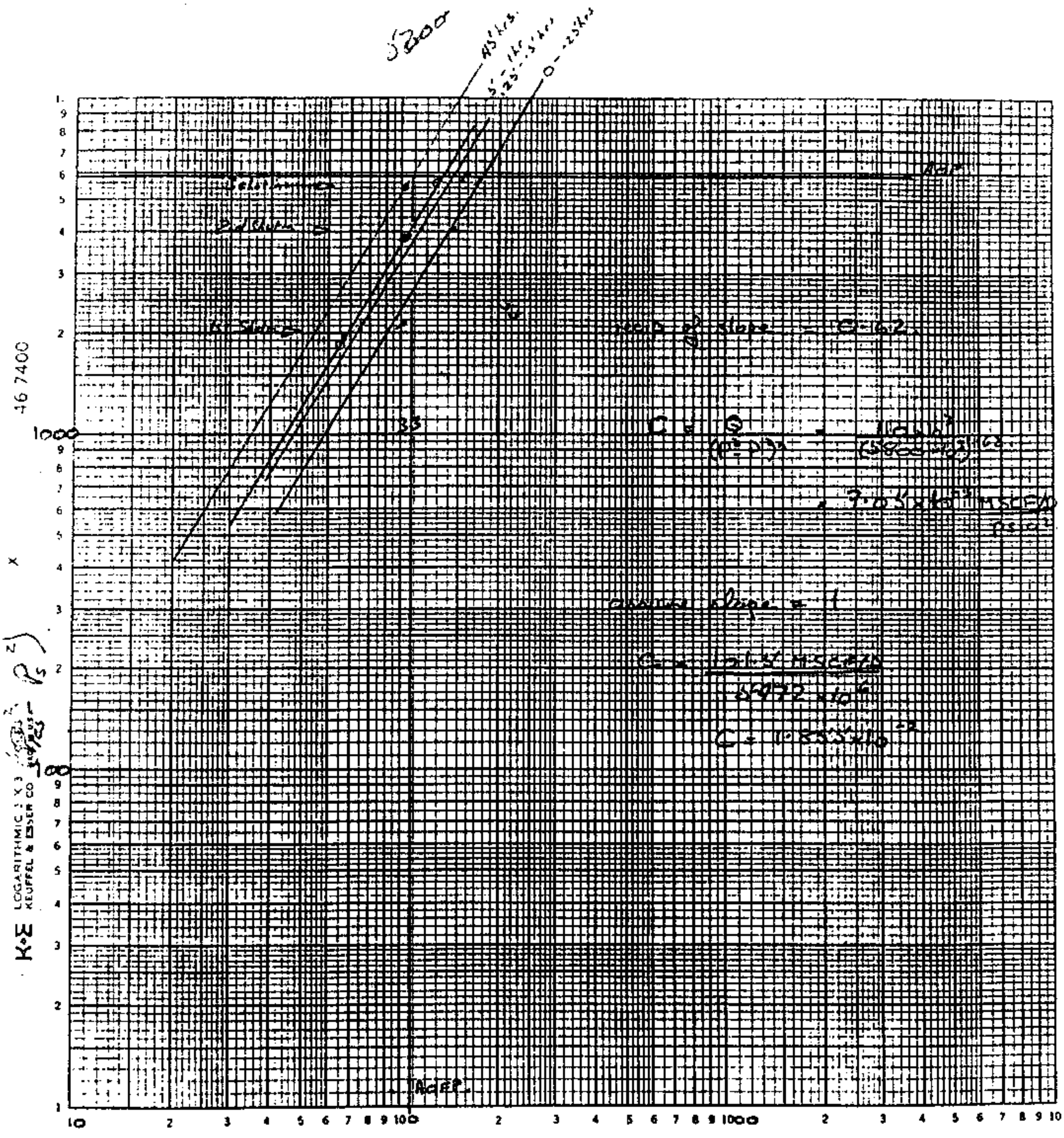
| $P_{SURF}$ | $(\Delta P)^2$ | Q, MSCF | Q MSCF. |
|---|---|---|---|
| 100 | 5830 | 110.4. | 108.1. |
| 400 | 5649. | 108.3. | 104.8 |
| 700 | 5246 | 103.4. | 97.3 |
| 1000 | 4612 | 95.5 | 85.6. |
| 1500 | 3038 | 73.7. | 56.4 |

Wellbore Storage Calculation



BACK PRESSURE CURVE DERIVED

FROM MODIFIED ISOCHRONAL TEST NOV 1980



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