NETHERLAND, SEWELL & ASSOCIATES, INC.

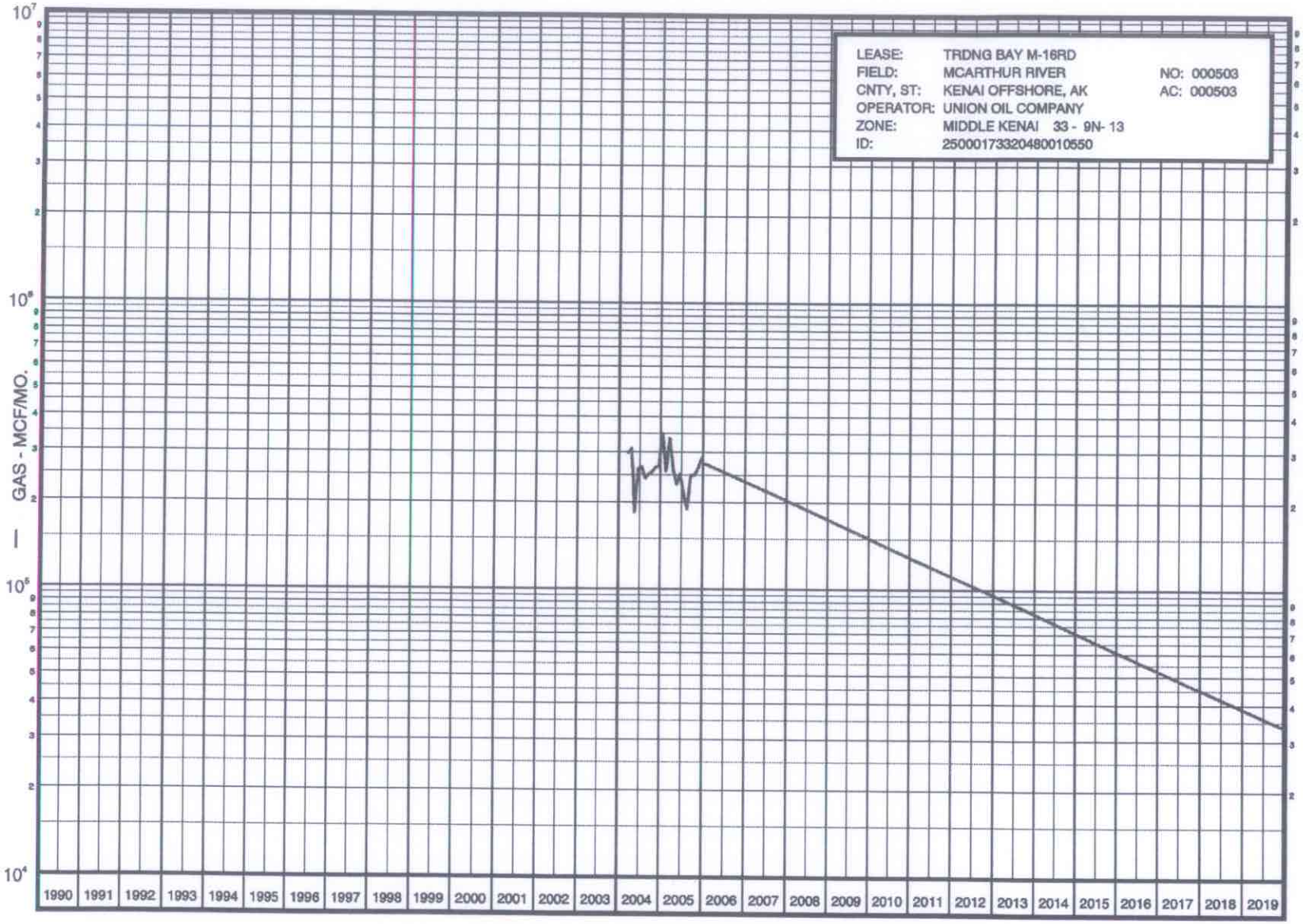

Figure 7.3.3.11

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Figure 7.3.3.12

8.0 NINILCHIK FIELD

8.1 OVERVIEW

Positioned in the southern portion of the Cook Inlet Basin and operated by Marathon, Ninilchik Field has produced, through December 2005, 28.7 BCF of gas from nine wellbores since production began in September 2003.

8.2 RESERVES SUMMARY

We estimate the gross (100 percent) gas reserves for Ninilchik Field, as of December 31, 2005, to be:

	Gross (100 Percent) Gas Reserves (BCF)	
Formation	1P	2P
Tyonek	56.4	82.5

8.2.1 Tyonek Formation

All nine wells at Ninilchik are completed in the Tyonek Formation. The ninth well began production in August 2005. For the 1P case, individual well-level decline curve analysis was performed resulting in estimated proved producing reserves, as of December 31, 2005, of 39.6 BCF of gas. Individual graphs showing historical and projected production are shown in Figure 8.3.1. The resulting summary plot showing gross historical and projected gas production along with average well count by year is shown in Figure 8.2.1.

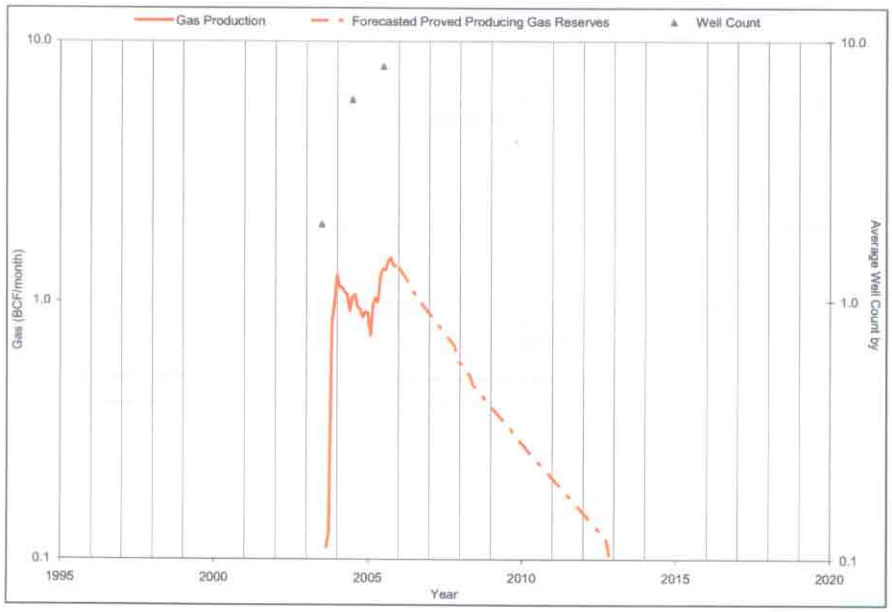

Figure 8.2.1 *Monthly historical and projected gas production and average well count by year for the active wells of the Ninilchik Tyonek Formation.*

Based on the *Second (2nd) Plan of Development and Operations* dated October 5, 2005, submitted by Marathon to the Alaska Department of Natural Resources, Marathon has drilled the GO#4 well and is evaluating three additional delineation wells for the Tyonek Formation. The average recovery for the current producing wells is 8.4 BCF of gas per well, with an EUR range of 2.2 to 19.7 BCF of gas. Therefore, we have included reserves for two additional wells at the average of 8.4 BCF of gas per well in the 1P case. The resulting 1P EUR is 56.4 BCF of gas. Two probable undeveloped locations are also included, each with an average recovery of 8.4 BCF of gas. The four undeveloped locations conform to the plan of development submitted by Marathon to the AOGCC.

Reserves for probable behind pipe zones in existing wells have been estimated using volumetric methods. Digital log data for existing wells were provided by the AOGCC, and were processed and analyzed to determine net feet of pay, porosity, and water saturation for each zone. Recovery factors are based on analogous production in the Tyonek Formation in Ninilchik. A total of nine zones were evaluated from two wells, with probable behind pipe reserves of 9.3 BCF of gas.

The following table summarizes the gross (100 percent) gas reserves, as of December 31, 2005, for the Ninilchik Tyonek Formation:

Category	Gross (100 Percent) Gas Reserves (BCF)
Proved Developed Producing	39.6
Proved Undeveloped	16.8
Total Proved (1P)	56.4
Probable	26.1
Proved + Probable (2P)	82.5

FIGURES

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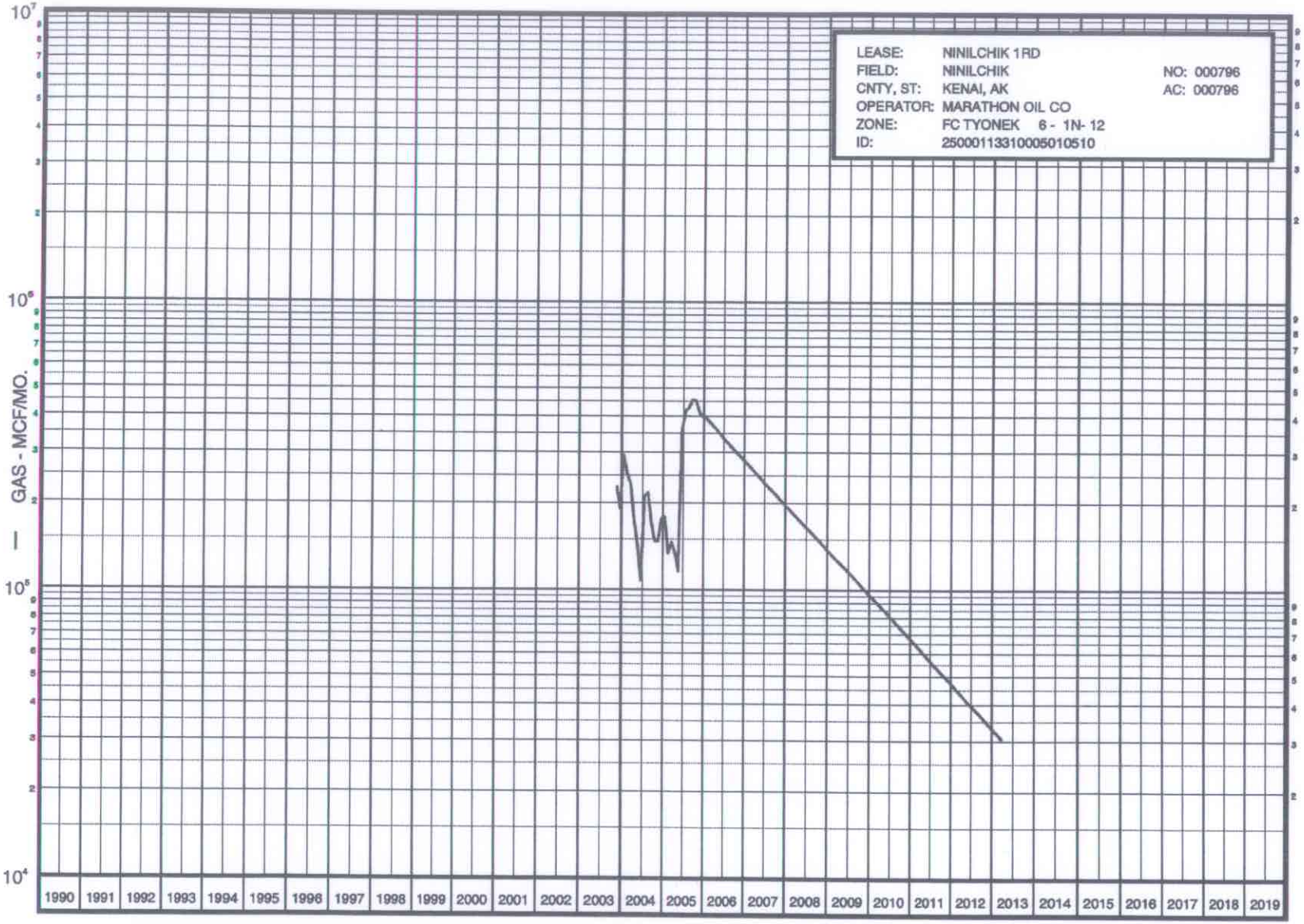

Figure 8.3.1.1

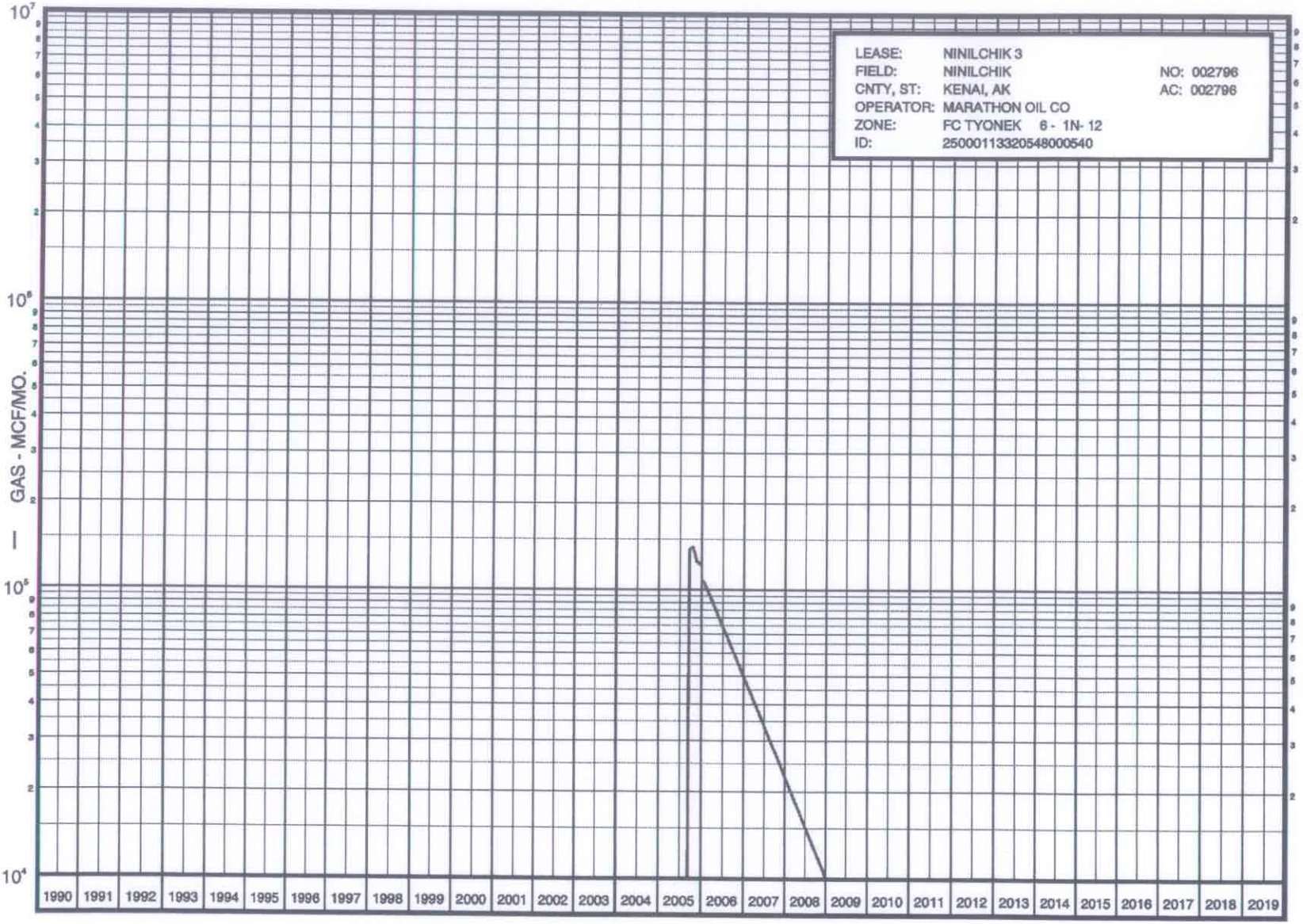

Figure 8.3.1.2

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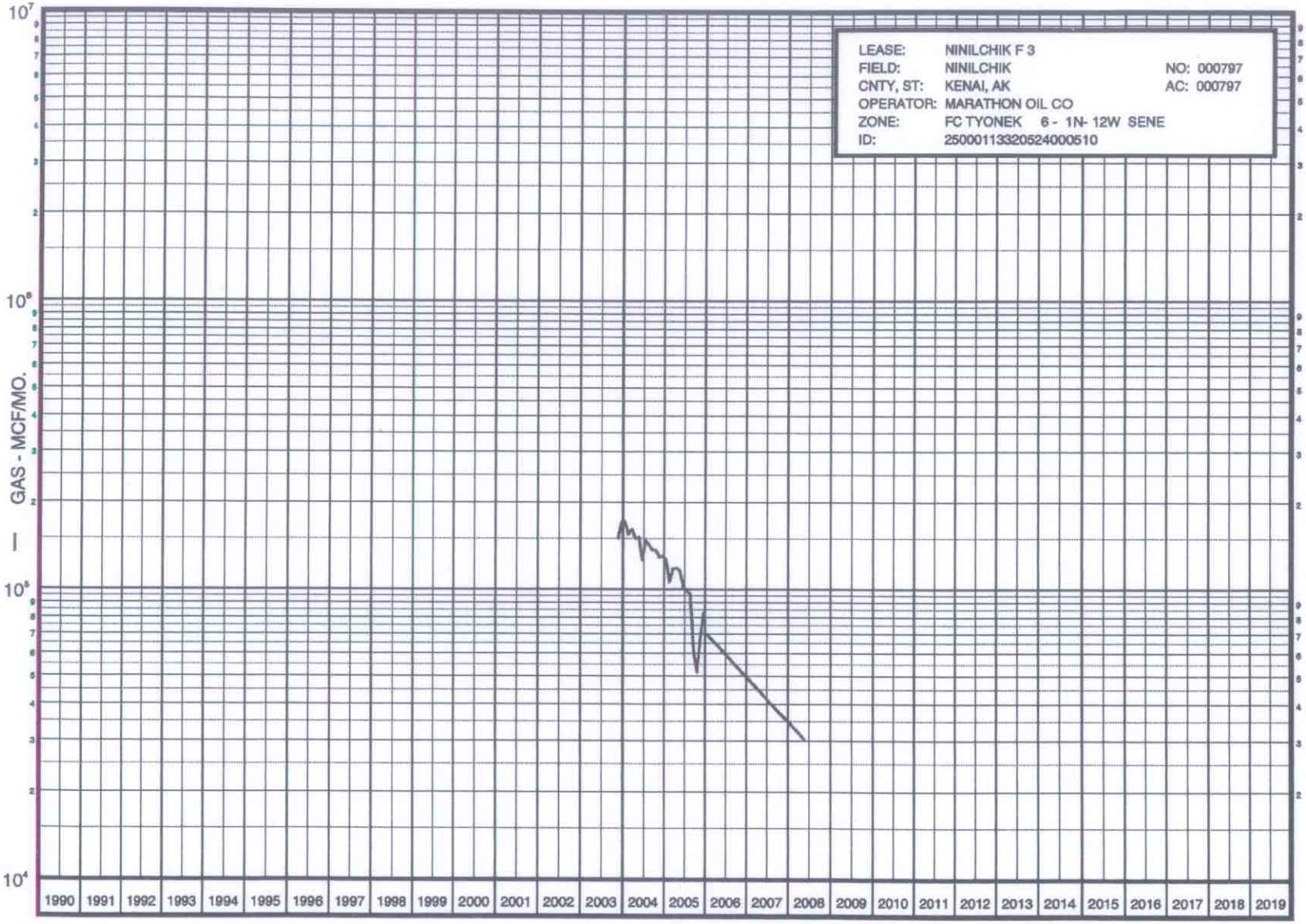

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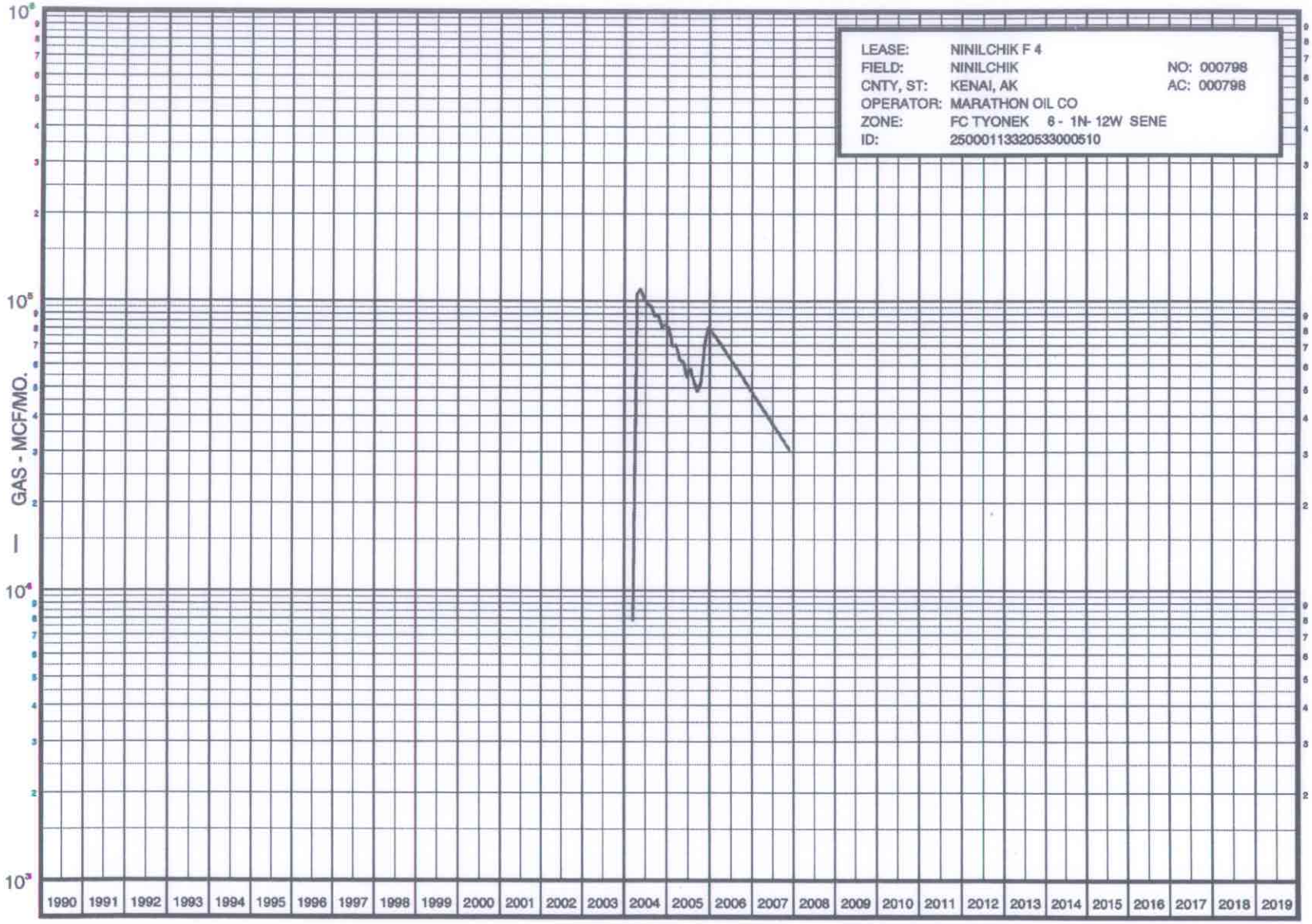
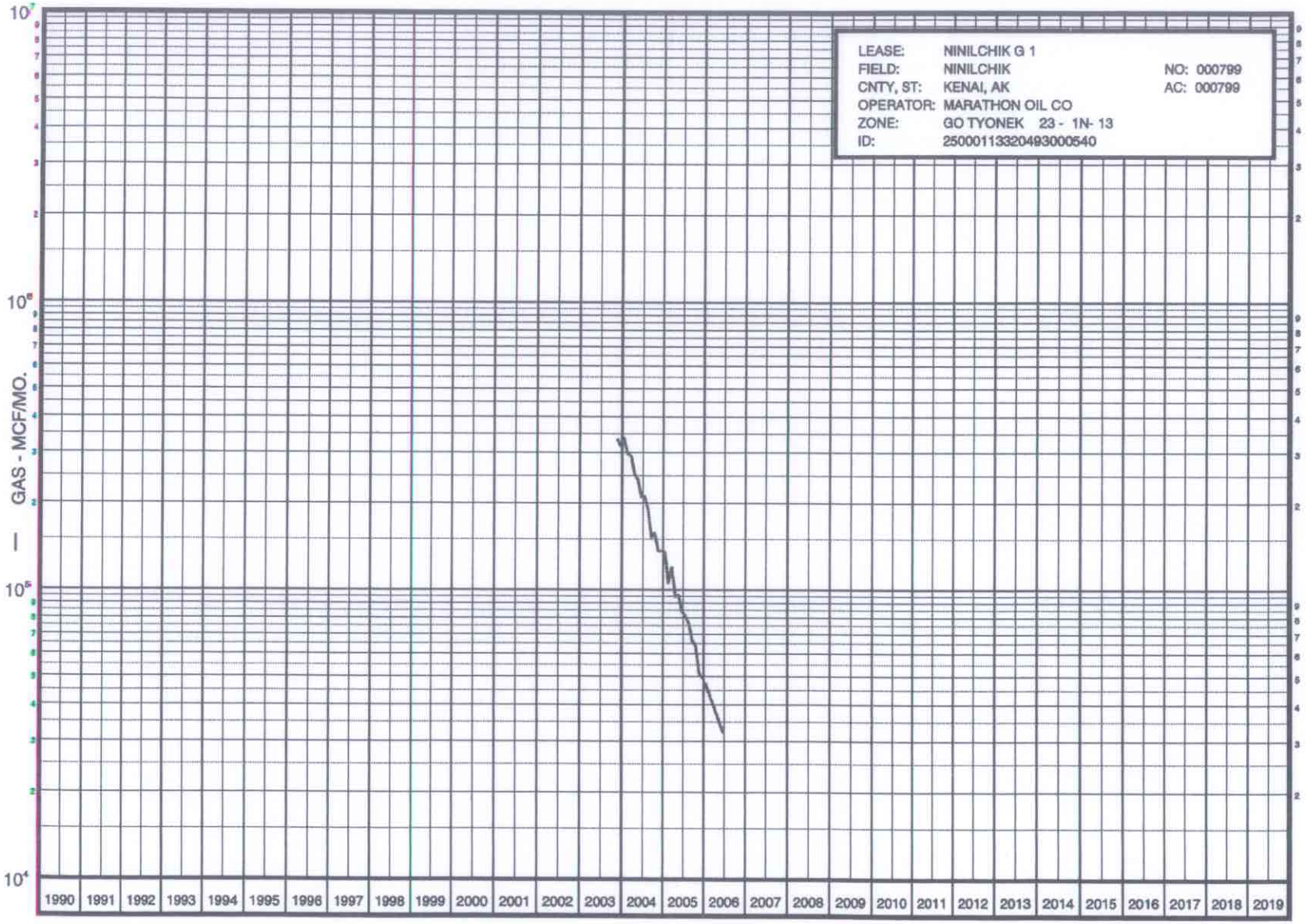


Figure 8.3.1.4



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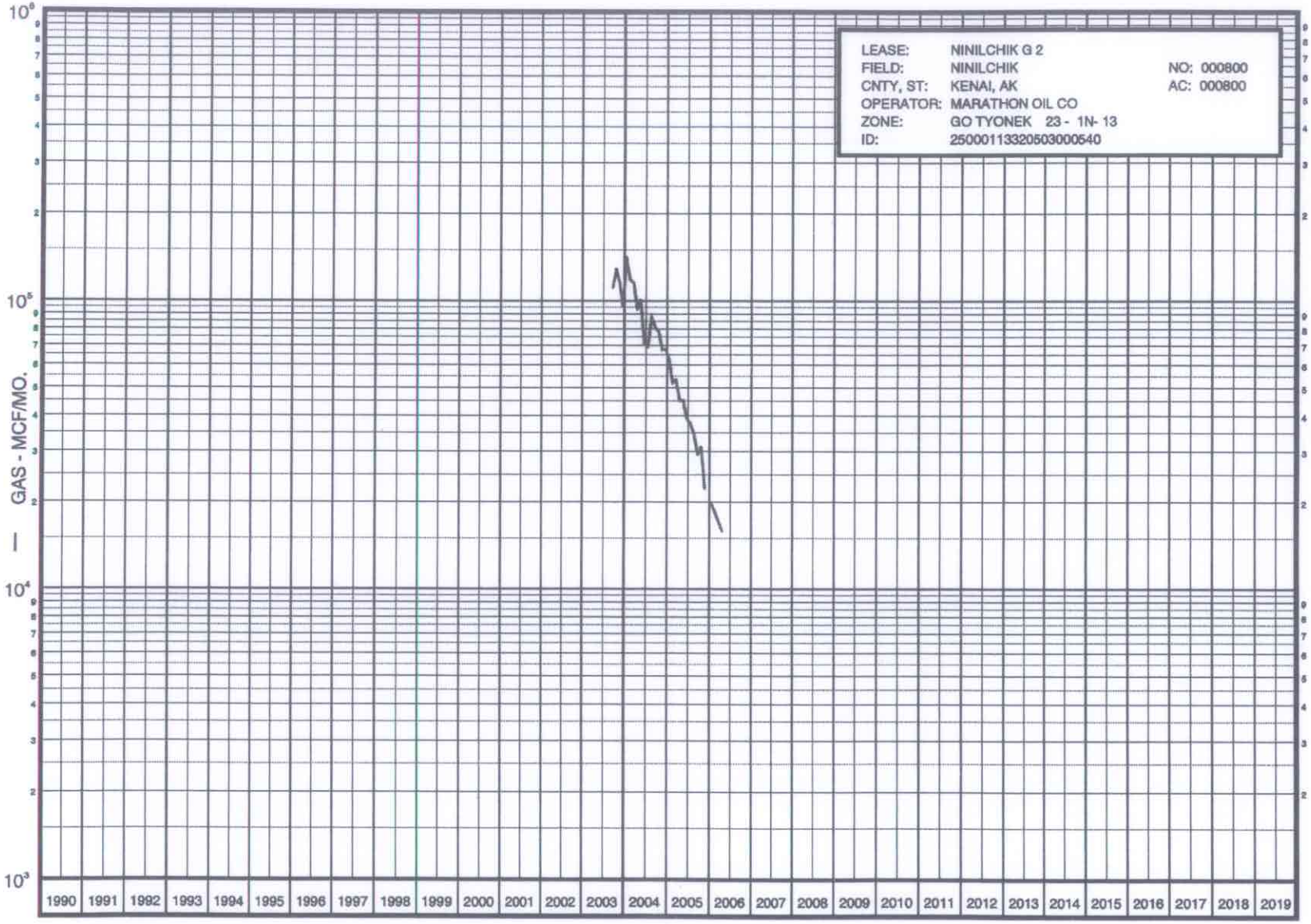


Figure 8.3.1.6

NETHERLAND, SEWELL & ASSOCIATES, INC.

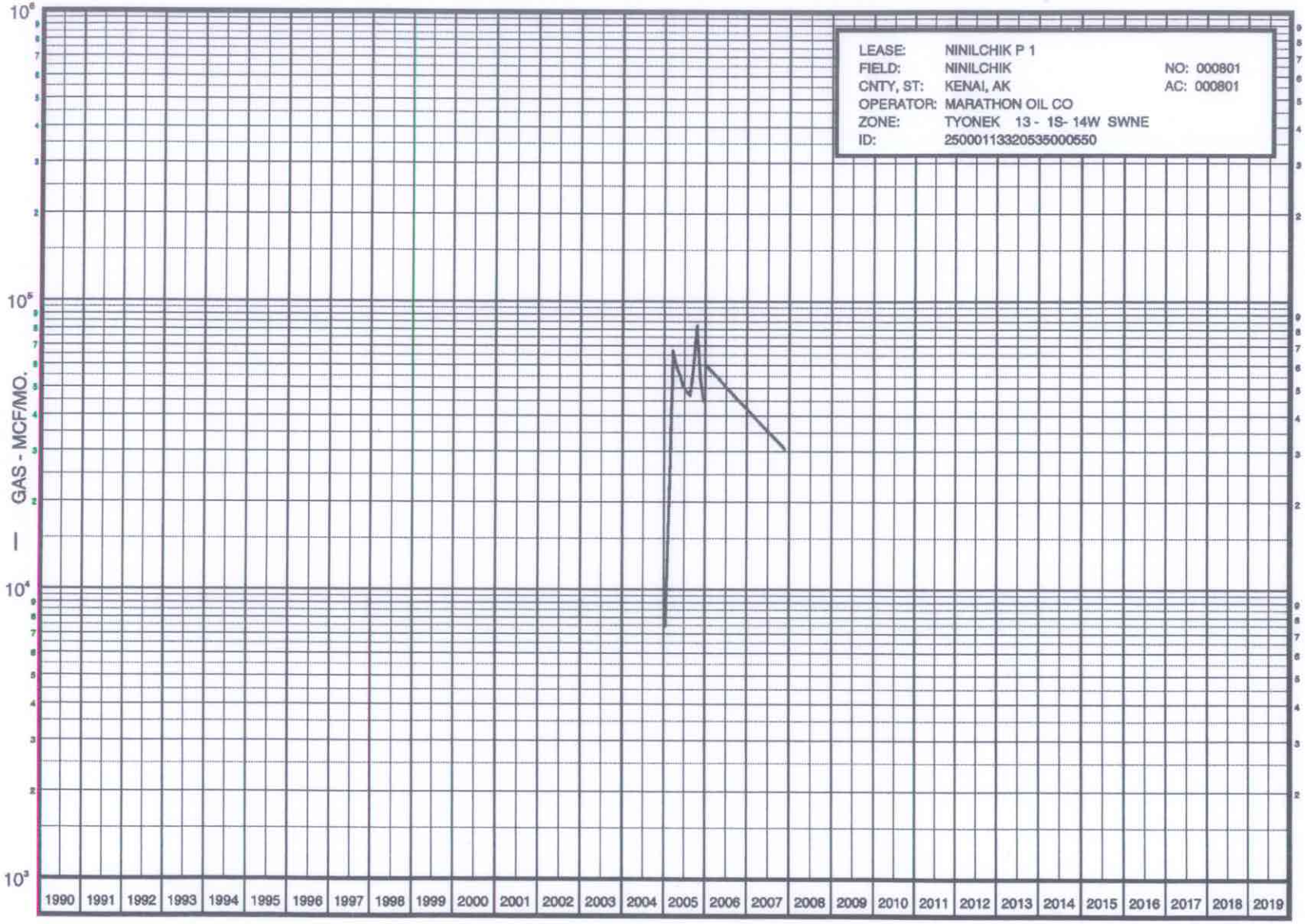
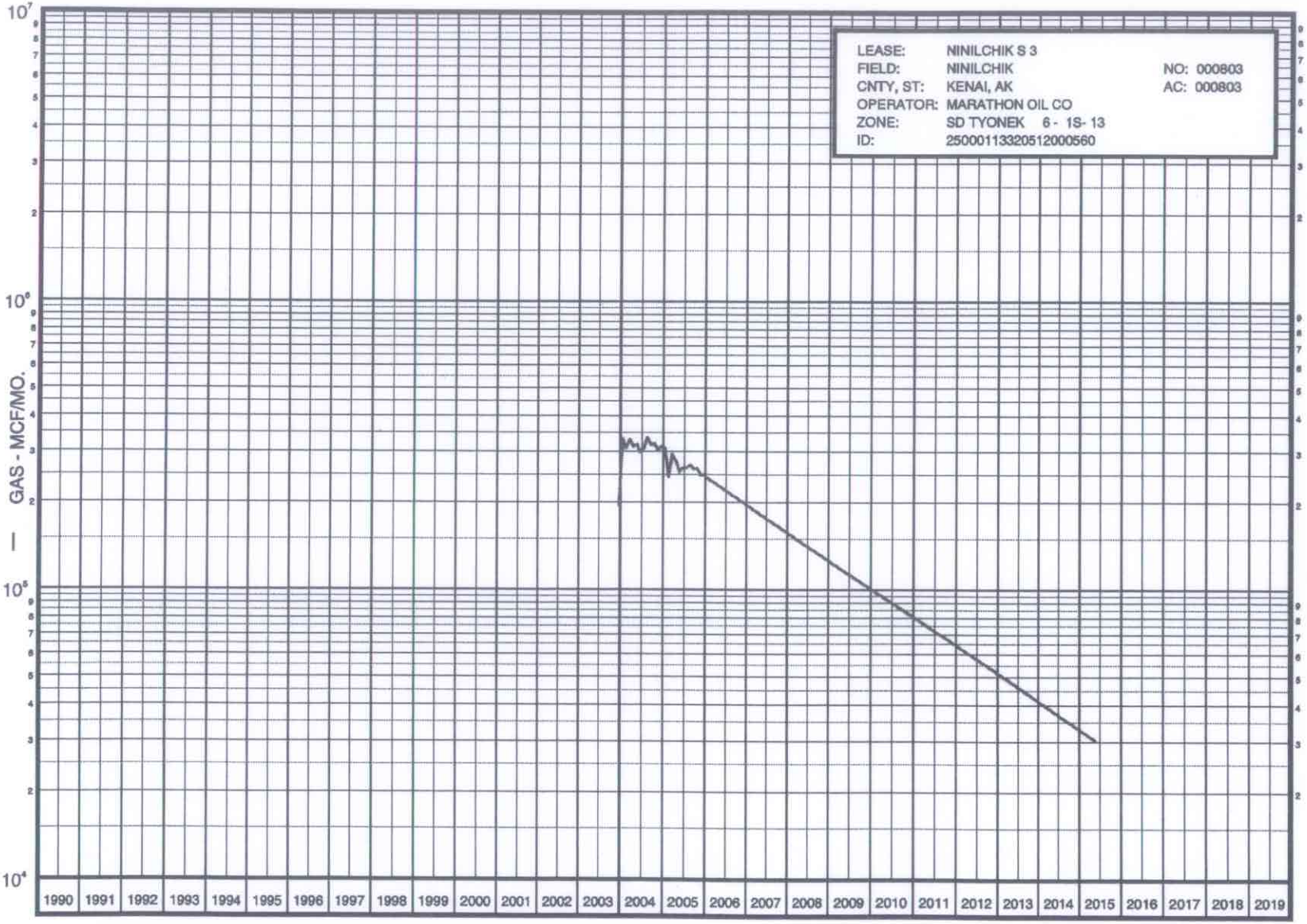


Figure 8.3.1.7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NO: 000803
CNTY, ST: KENAI, AK
AC: 000803
OPERATOR: MARATHON OIL CO
ZONE: SD TYONEK 6 - 1S- 13
ID: 25000113320512000560
GAS - MCF/MO.
10^7
10^6
10^5
10^4
1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019

Figure 8.3.1.8

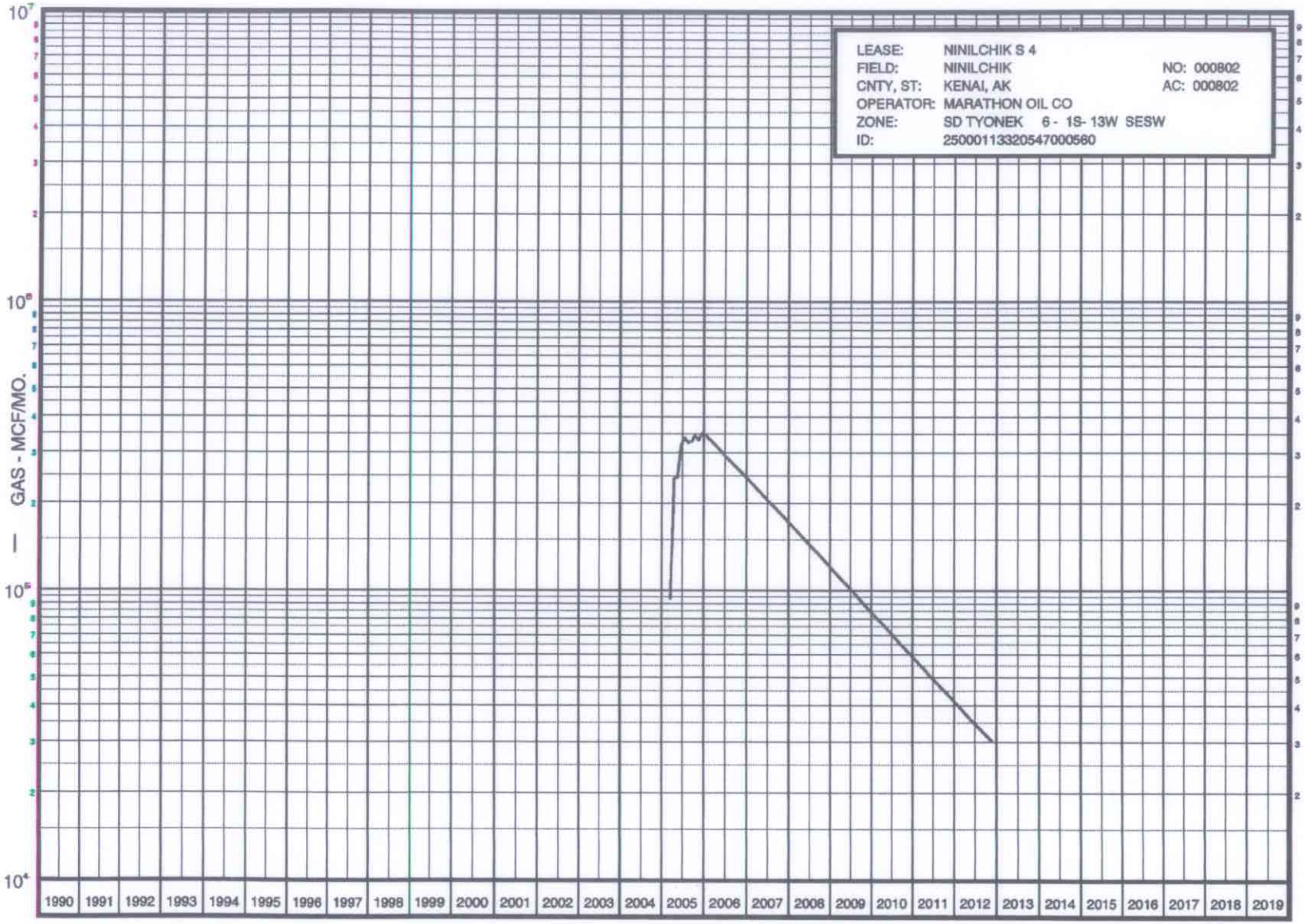
LEASE: NINILCHIK S 4
FIELD: NINILCHIK NO: 000802
CNTY, ST: KENAI, AK AC: 000802
OPERATOR: MARATHON OIL CO
ZONE: SD TYONEK 6 - 1S- 13W SESW
ID: 25000113320547000560
GAS - MCF/MO.
10^7
10^6
10^5
10^4
1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019

Figure 8.3.1.9

9.0 NORTH COOK INLET FIELD

9.1 OVERVIEW

North Cook Inlet Field was discovered in 1962 and is currently operated by ConocoPhillips. Production began in March 1969 with the drilling of the A-2 well. Cumulative production from both the Sterling and Beluga Formations, as of December 31, 2005, is 1,710.6 BCF of gas with 13 active producing wells. The monthly historical gas production and average well count by year are shown in Figure 9.1.1. A location map and representative structure map are shown in Figure 9.3.1 and Figure 9.3.2, respectively.

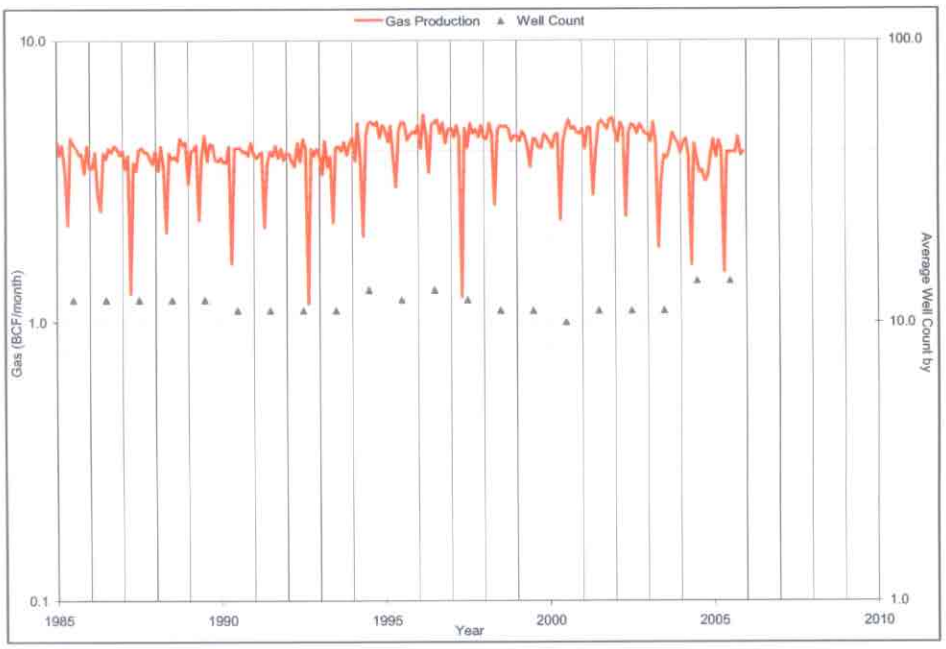

Figure 9.1.1 *Monthly historical gas production and average well count by year for the North Cook Inlet Field.*

9.2 RESERVES SUMMARY

We estimate the gross (100 percent) gas reserves for North Cook Inlet Field, as of December 31, 2005, to be:

Formation	Gross (100 Percent) Gas Reserves (BCF) 1P	2P
Sterling and Beluga	350.3	610.2

9.2.1 Sterling and Beluga Formations

The original well pressure data available through the AOGCC for the North Cook Inlet Sterling and Beluga Formations are shown in the material balance plot in Figure 9.2.1.

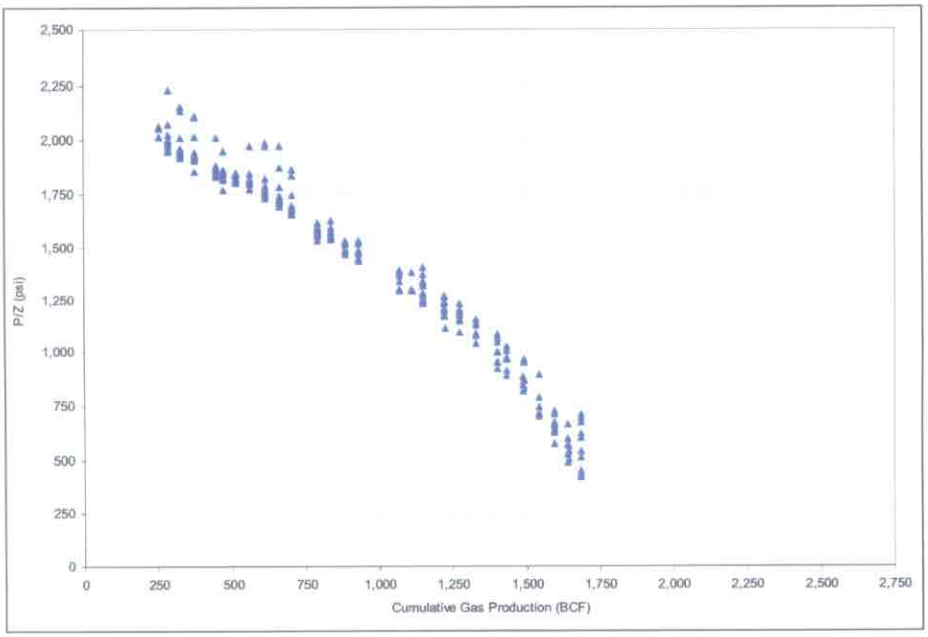

Figure 9.2.1 *Material balance graph using raw data from the AOGCC for the North Cook Inlet Sterling and Beluga Formations.*

The pressure data shown in Figure 9.2.2 represent an arithmetic average of all the yearly pressure data available through the AOGCC, in most cases ranging between 9 and 11 values annually. The graph shows an abrupt change downward in the slope of the data at a cumulative gas production of approximately 1,300 BCF. As suggested in previous literature, and supported by the historical well data available through the AOGCC, this change in slope is due in large part to a wellwork program performed in the mid-1990s in which many active perforations were squeezed or plugged back (Thomas, 2004). The purpose of this wellwork program appears to have been to plug off minor water producing zones primarily found in the Sterling Formation in at least four wellbores. The effect of this work reduced the relative size of the reservoir that remained in communication with the still active completions, essentially reducing the OGIP value. The available pressure data, along with the known geologic setting, would suggest the perceived inflection point in the P/Z versus G_p plot is not indicative of water influx in the form of active aquifer pressure support. This becomes evident in looking at the historical produced-water- to-produced-gas ratio, which has an average value of less than 0.005 barrels of water per MCF of gas over the last two years. The OGIP estimate using the data prior to the slope change is 2,546.0 BCF (Trend line 2) whereas an OGIP estimate of 2,020.3 BCF (Trend line 1) results from using only the later time data following the change in slope.

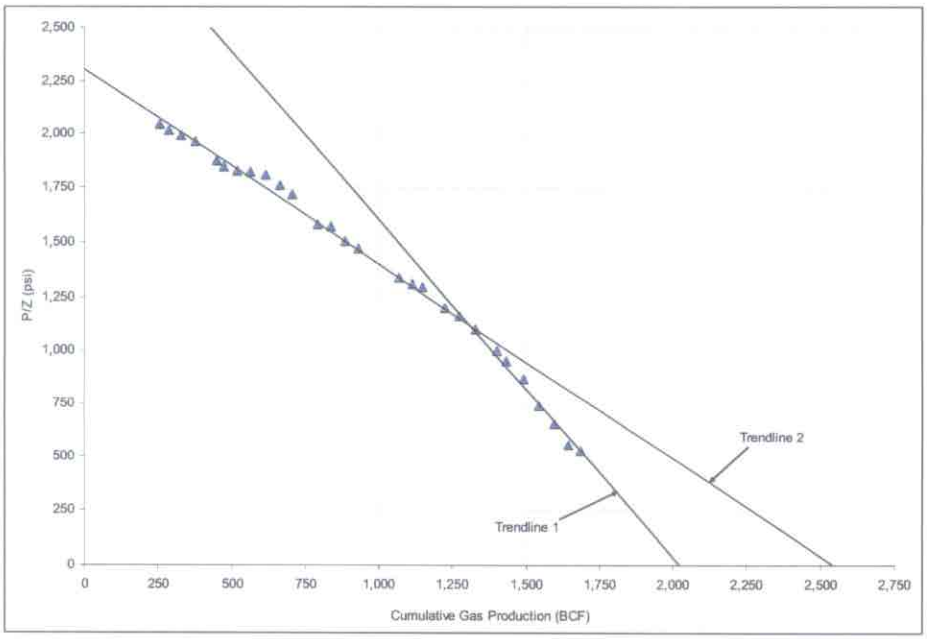

Figure 9.2.2 *Material balance graph from arithmetic averages of all the yearly pressure data available through the AOGCC for the North Cook Inlet Sterling and Beluga Formations.*

Trend line 1 in Figure 9.2.2 represents only the portion of 1P gross gas reserves that will be captured through the existing wellbores in the field. However, there is another portion of the 1P reserves that include behind pipe zones in producing wells along with future infill drilling locations. Therefore, the resulting P/Z trend for the total 1P reserves, including both producing and non-producing portions, lies between the two trend lines depicted in Figure 9.2.2.

By nature of the geologic setting, any future well drilled infill to the existing wells or any behind pipe zone added to the existing wells should experience an average pressure within the range of all pressures taken in the field. To estimate 1P reserves for this field, the highest value of the individual well annual pressures after the change in slope, shown in Figure 9.2.1, is plotted on the P/Z versus G_p plot, as shown in Figure 9.2.3. The resulting estimate of OGIP is 2,270.0 BCF. Based on an abandonment pressure of 250 psi, the 1P EUR is 2,060.9 BCF of gas, with a recovery efficiency of approximately 91 percent.

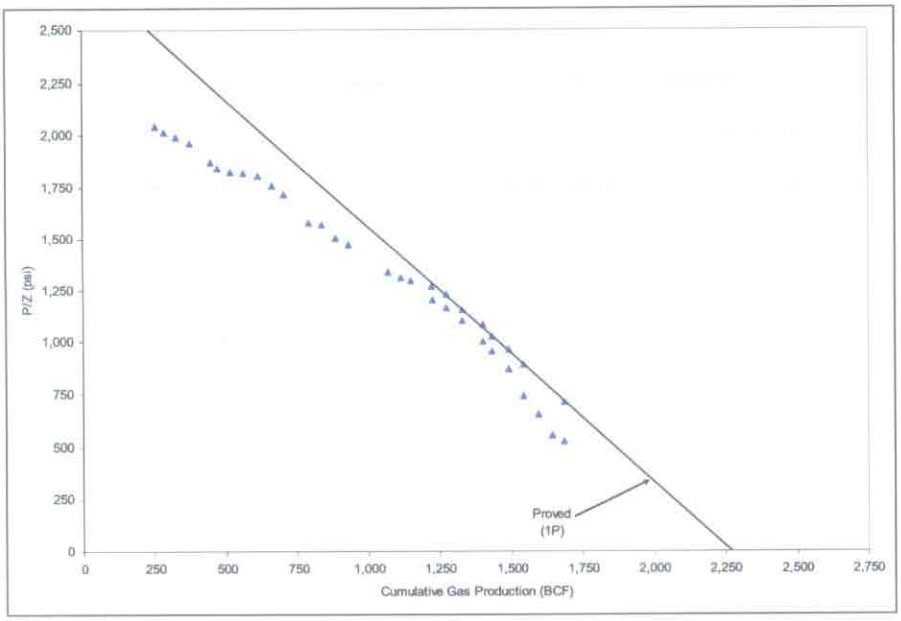

Figure 9.2.3 *1P material balance graph for the North Cook Inlet Sterling and Beluga Formations using the highest value after the change in slope from each yearly arithmetic average taken from data available through the AOGCC.*

To estimate 2P reserves for this field, the data prior to the change in slope of the individual well annual pressures shown in Figure 9.2.1 was used, as shown in Figure 9.2.4. The resulting estimate of OGIP is 2,546.0 BCF. Based on an abandonment pressure of 250 psi, the 2P EUR is 2,230.8 BCF of gas, with a recovery efficiency of approximately 91 percent.

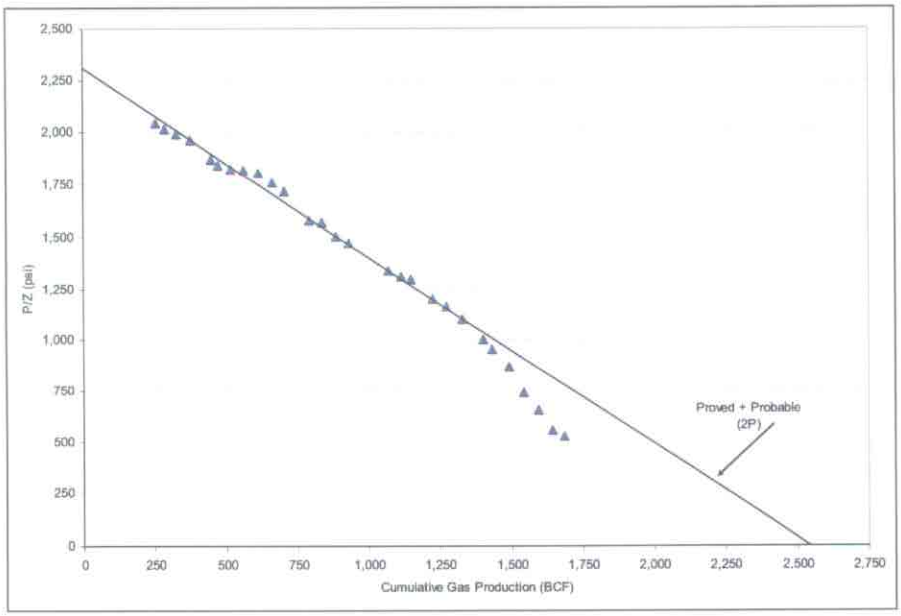

Figure 9.2.4 *2P material balance graph for the North Cook Inlet Sterling and Beluga Formations.*

The following table summarizes the material balance parameter/result for the North Cook Inlet Sterling and Beluga Formations:

Parameter/Result	Gas (BCF) 1P	Gas (BCF) 2P
Original Gas-in-Place	2,270.0	2,546.0
Cumulative Production through 12-31-2005	1,710.6	1,710.6
Estimated Ultimate Recovery	2,060.9	2,320.8
Gross (100 Percent) Reserves, as of 12-31-2005	350.3	610.2

FIGURES

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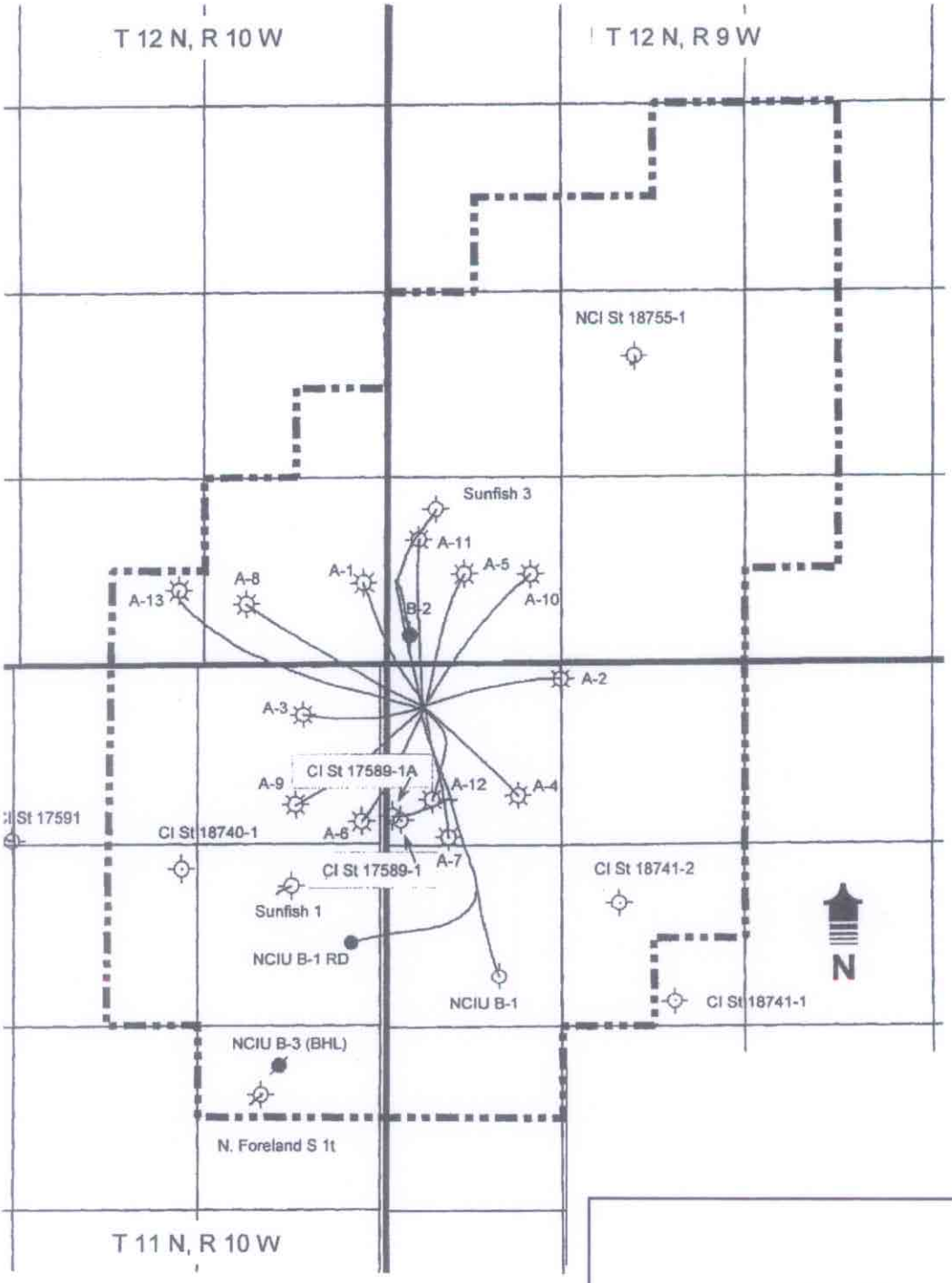


Location Map

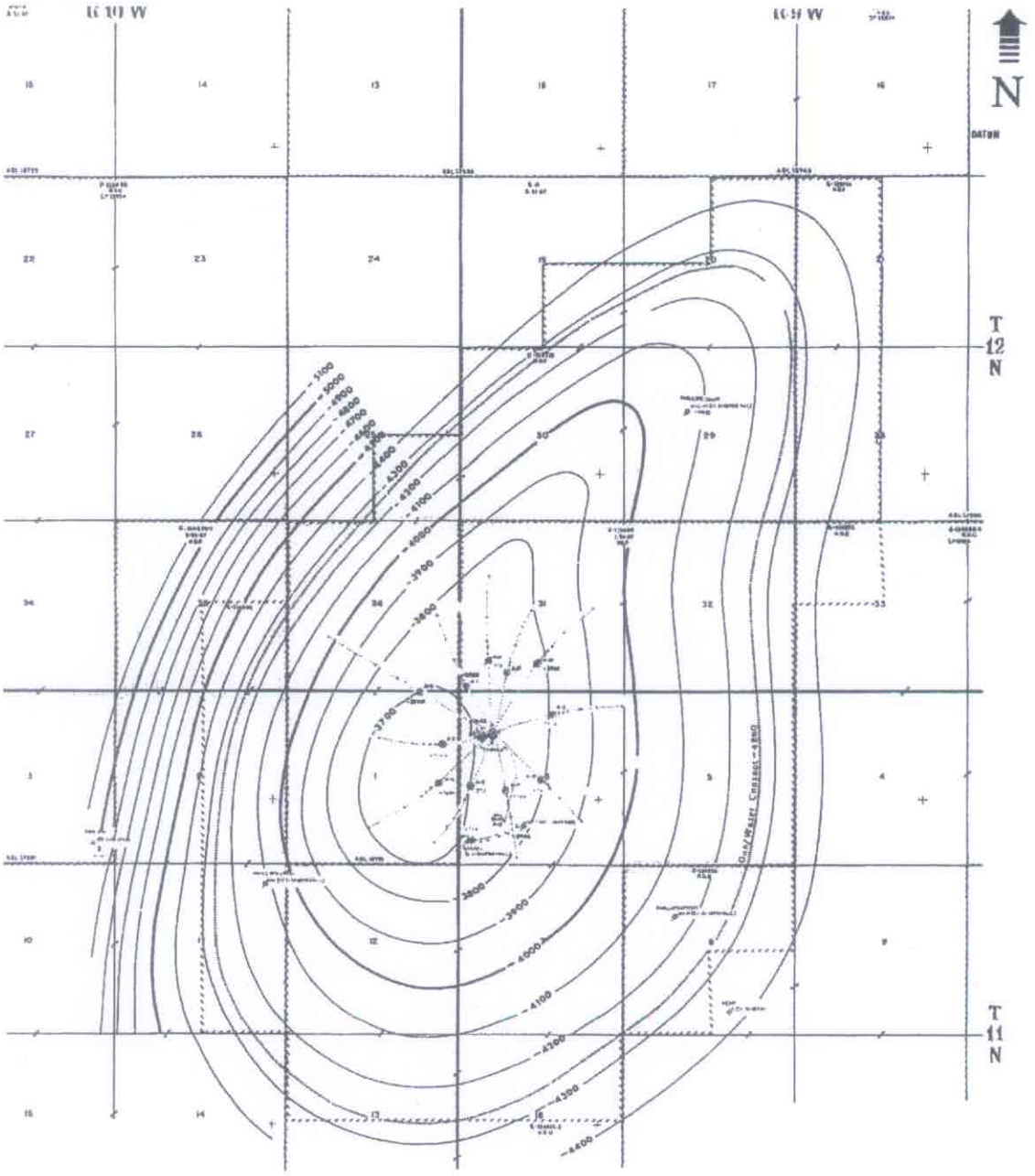
North Cook Inlet Field
Cook Inlet Region, Alaska

Important Note:

The presented material was assembled and revised by Netherland, Sewell & Associates, Inc. ("NSAI") from data and interpretations provided by public domain sources including the Alaska Oil and Gas Conservation Commission. This exhibit is for illustrative purposes only and we have not verified the content thereon.

Figure 9.3.1

NETHERLAND, SEWELL & ASSOCIATES, INC.



0 1 Mile
Scale

Structure Map
Top Cook Inlet Sand #1

North Cook Inlet Field
Cook Inlet Region, Alaska

Important Note:

The presented material was assembled and revised by Netherland, Sewell & Associates, Inc. ("NSAI") from data and interpretations provided by public domain sources including the Alaska Oil and Gas Conservation Commission. This exhibit is for illustrative purposes only and we have not verified the content thereon.

Figure 9.3.2

10.0 OTHER FIELD AREA

10.1 OVERVIEW

The Other field area is comprised of the remaining 15 active fields located in the Cook Inlet Region of Alaska. The proved reserves for the Other field area are based on individual well-level decline curve analysis. The proved plus probable reserves are based on field-level decline curve analysis. Both data sets were projected using methods for decline curve analysis. No attempt was made to perform material balance or volumetric calculations for these field accumulations.

10.2 DECLINE CURVE ANALYSIS OF INDIVIDUAL WELLS

We estimate the gross (100 percent) 1P gas reserves for fields in the Other area, as of December 31, 2005, to be:

Field	Gross (100 Percent) 1P Gas Reserves (BCF)
Albert Kaloa	3.0
Deep Creek	8.7
Foreland, West	7.3
Granite Point	8.3
Ivan River	4.4
Lewis River	1.5
McArthur River, West	0.8
Middle Ground Shoal	3.4
Nicolai Creek	0.7
Oskoloff G	0.0
Redoubt Shoal	0.3
Sterling	13.8
Swanson River	6.0
Three Mile Creek	1.5
Trading Bay	1.1
Total	60.6

Totals may not add because of rounding.

A summary graph showing gross historical and projected gas production along with average well count by year is shown in Figure 10.2.1. Individual graphs of historical and projected gas production are shown in Figure 10.5.1. The aggregate of these individual forecasts yields 1P gas reserves of 60.6 BCF.

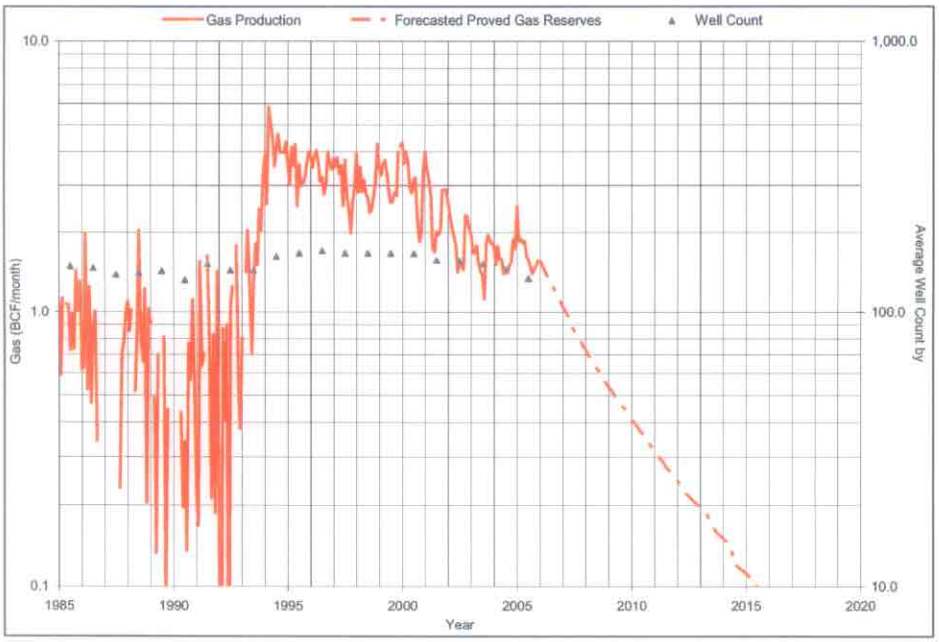


Figure 10.2.1 *Summary of monthly historical and projected gas production along with average well count by year using individual well-level decline curve analysis for the Other field area.*

10.3 DECLINE CURVE ANALYSIS OF FIELD-LEVEL DATA

We estimate the gross (100 percent) 2P gas reserves for fields in the Other area, as of December 31, 2005, to be:

Field	Gross (100 Percent) 2P Gas Reserves (BCF)
Albert Kaloa	4.0
Deep Creek	22.0
Foreland, West	14.2
Granite Point	8.3
Ivan River	9.6
Lewis River	1.5
McArthur River, West	0.8
Middle Ground Shoal	3.4
Nicolai Creek	0.7
Oskoloff G	1.1
Redoubt Shoal	0.3
Sterling	13.8
Swanson River	6.0
Three Mile Creek	3.8
Trading Bay	1.5
Total	90.9

Totals may not add because of rounding.

The summary graph of historical and projected gas production along with average well count by year for the field-level decline curve analysis is shown in Figure 10.3.1. 2P reserves from this method are estimated to be 90.9 BCF of gas. Graphs showing gross historical and projected field-level gas production are shown in Figure 10.5.2.

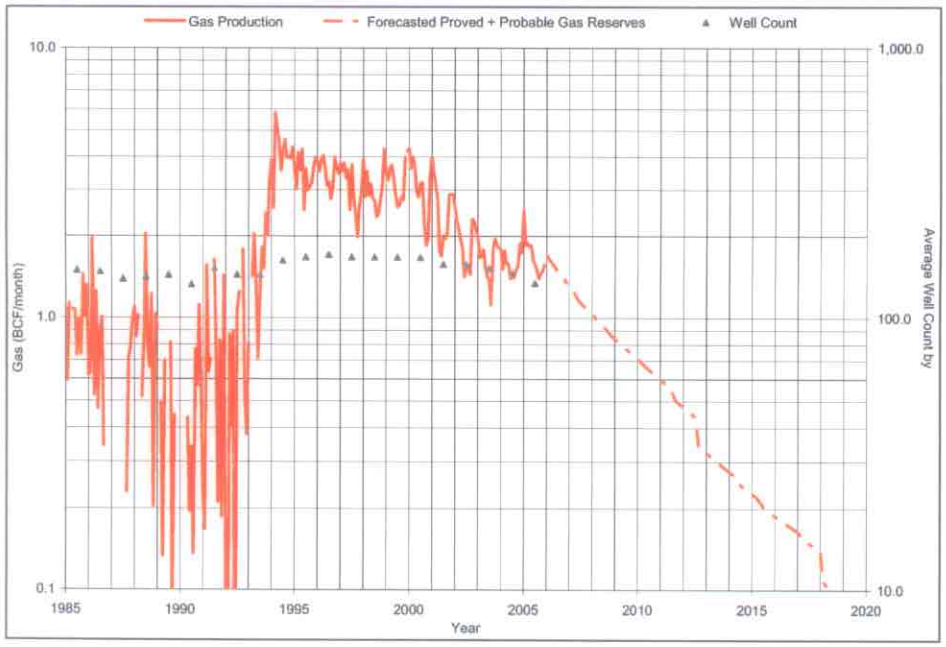


Figure 10.3.1 *Summary of monthly historical and projected gas production along with average well count by year using field-level decline curve analysis for the Other field area.*

FIGURES

NETHERLAND, SEWELL & ASSOCIATES, INC.

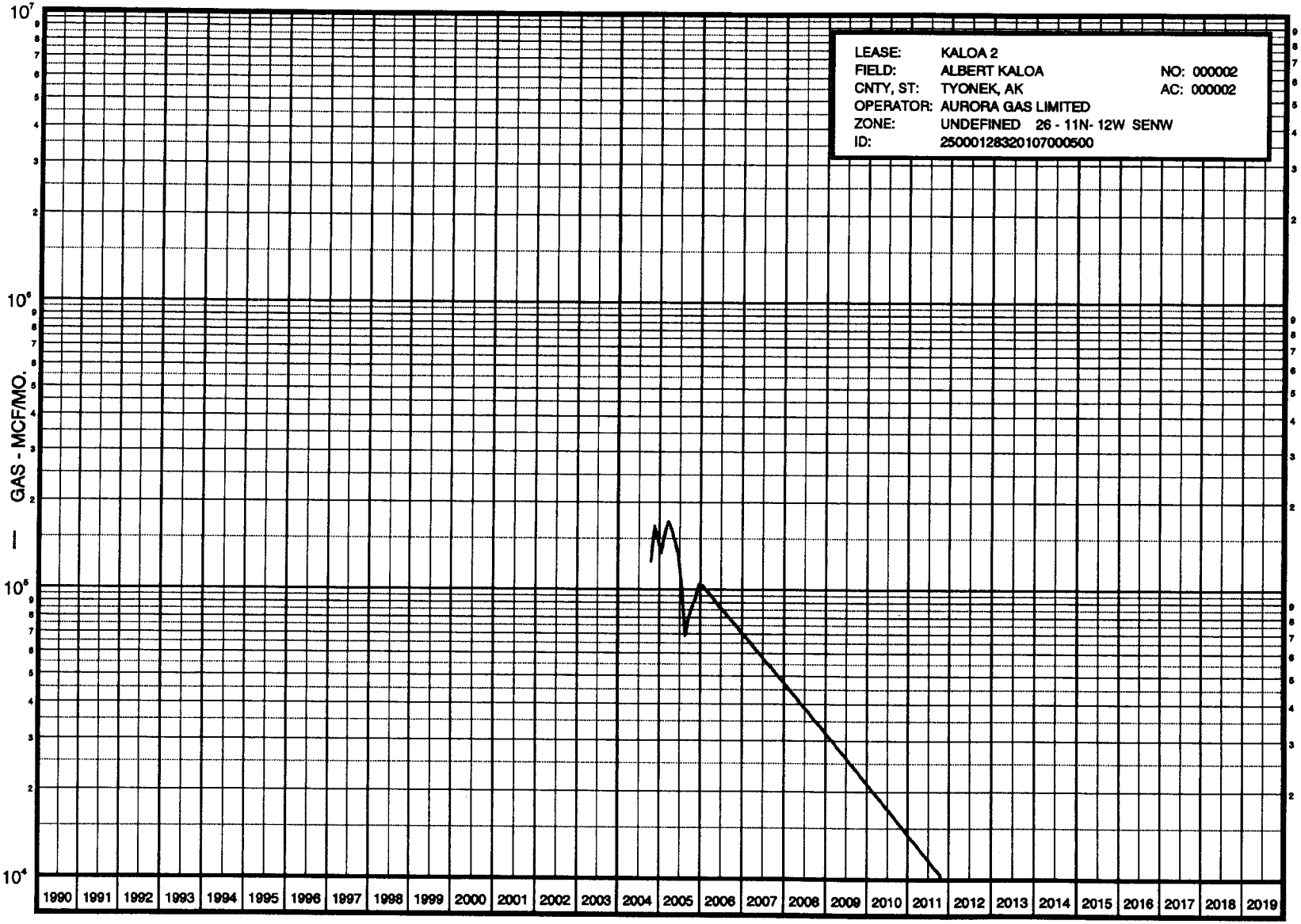


Figure 10.4.1.1

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

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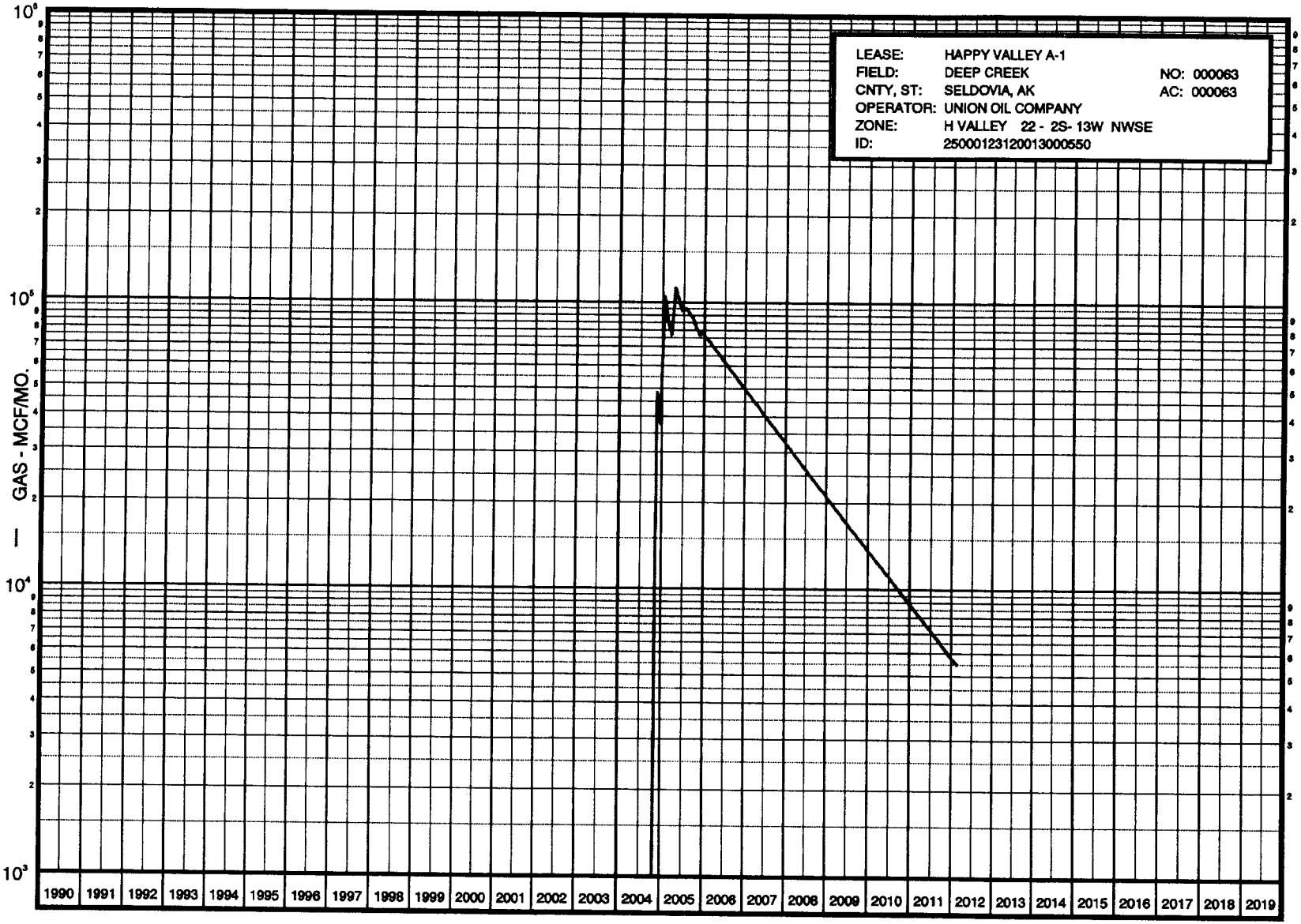

Figure 10.4.1.2

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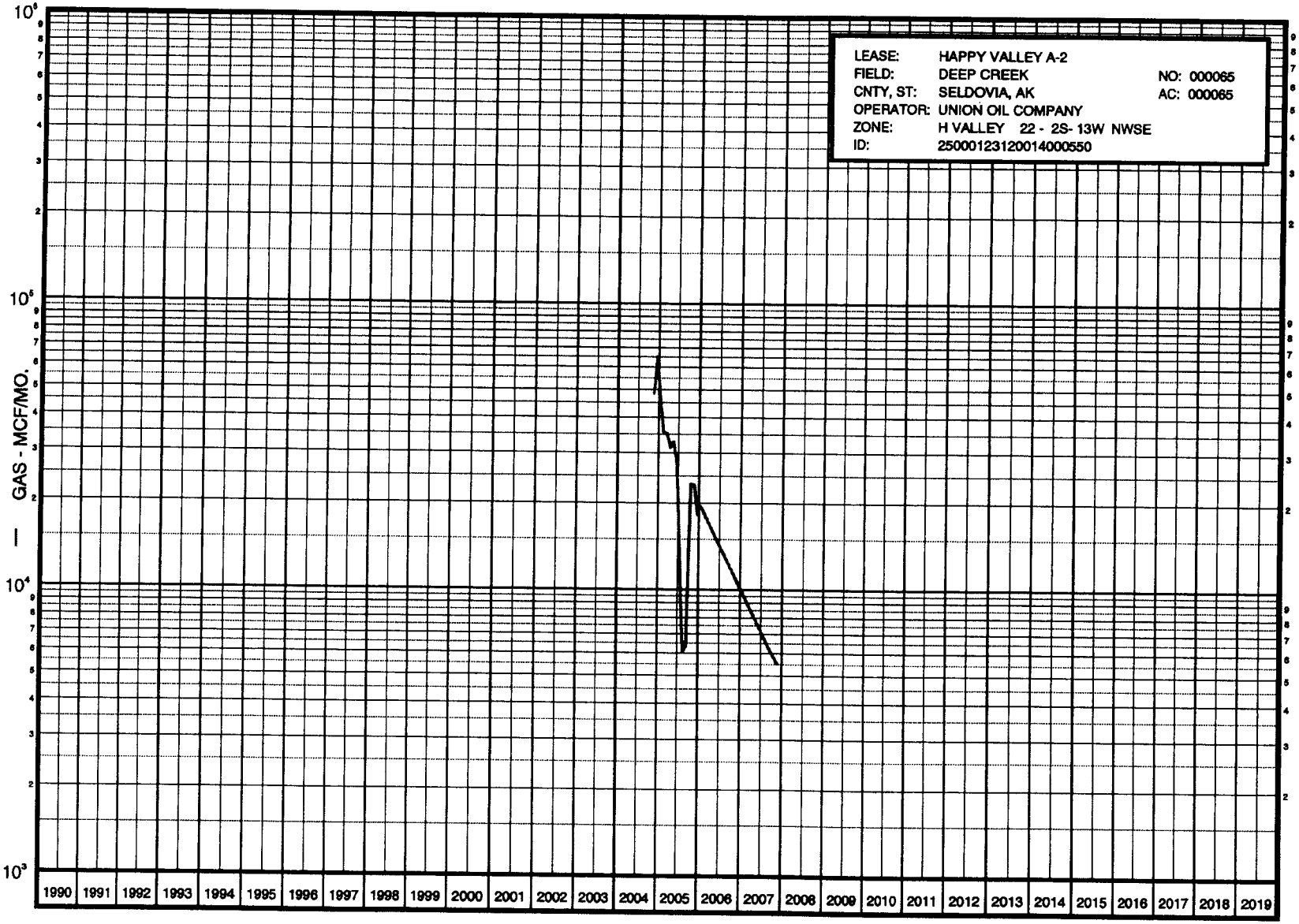

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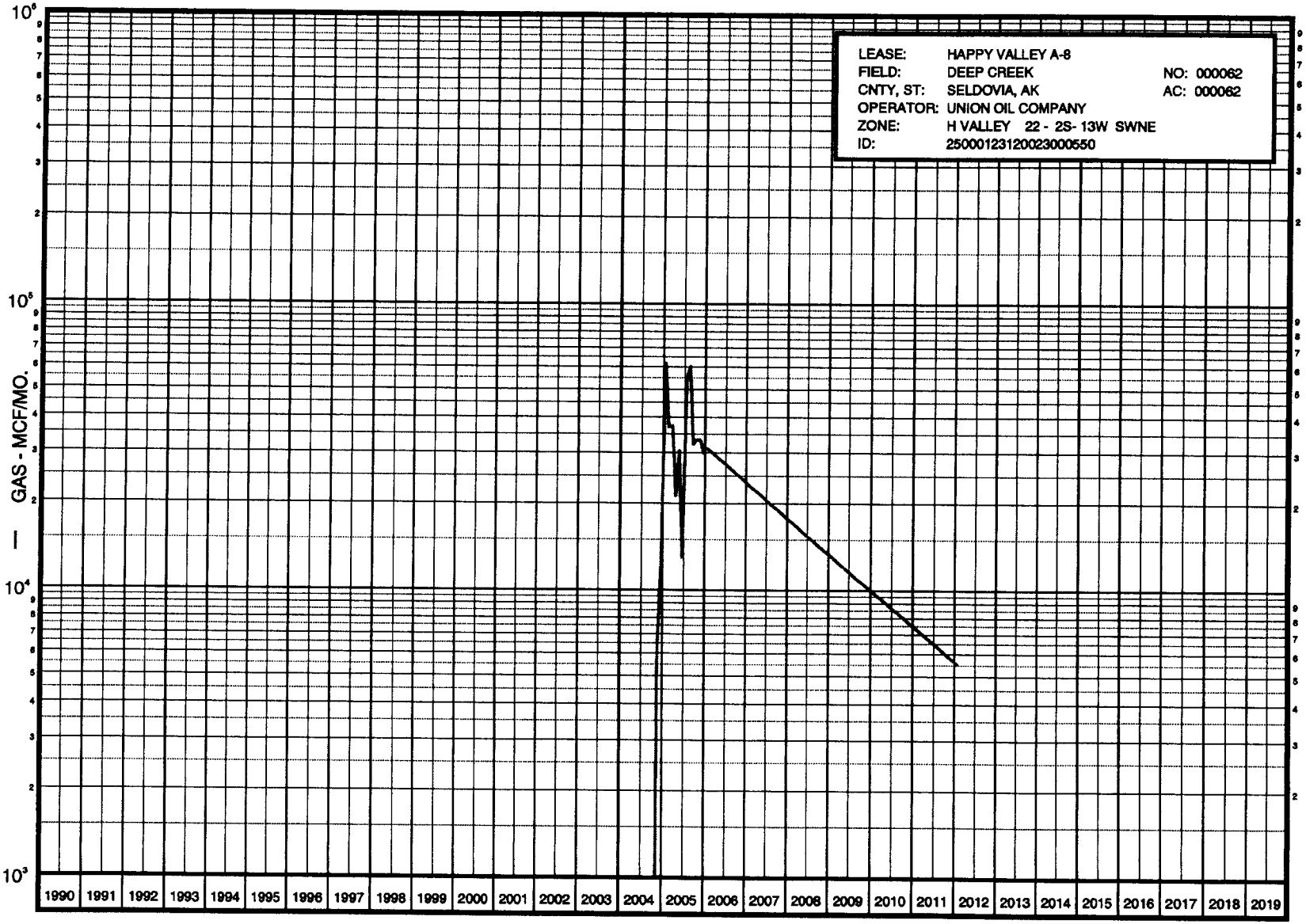

Figure 10.4.1.4

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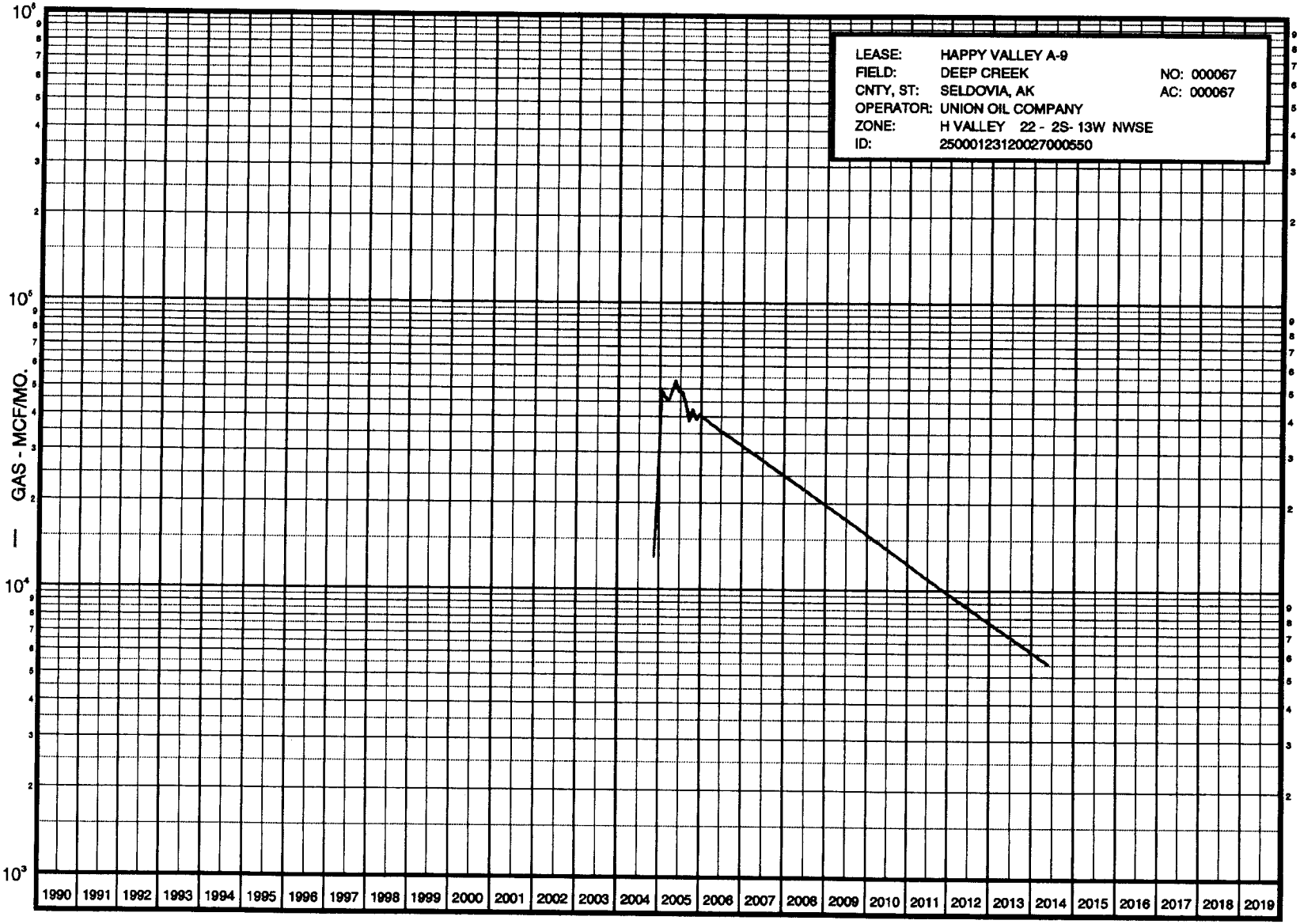

Figure 10.4.1.5

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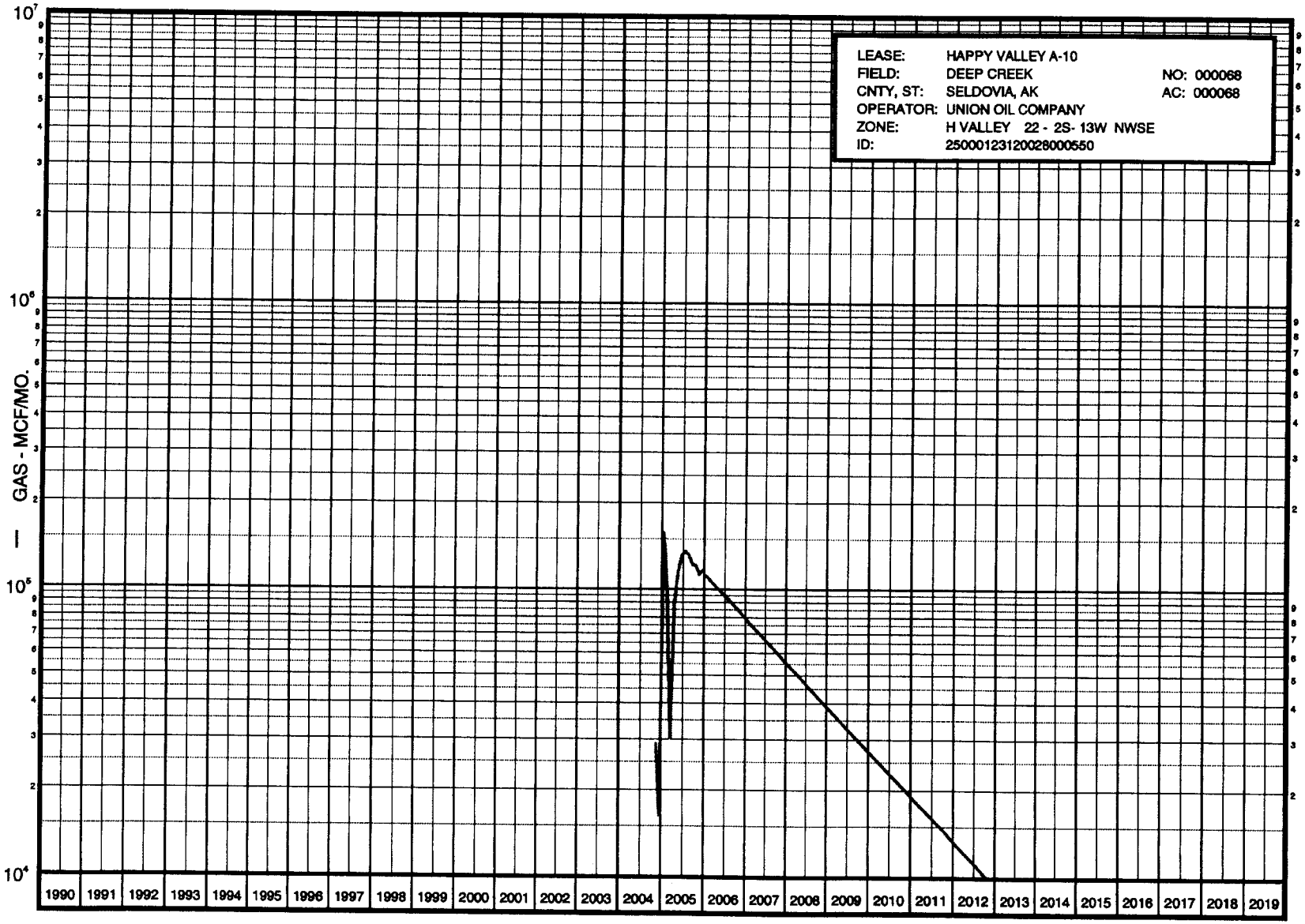

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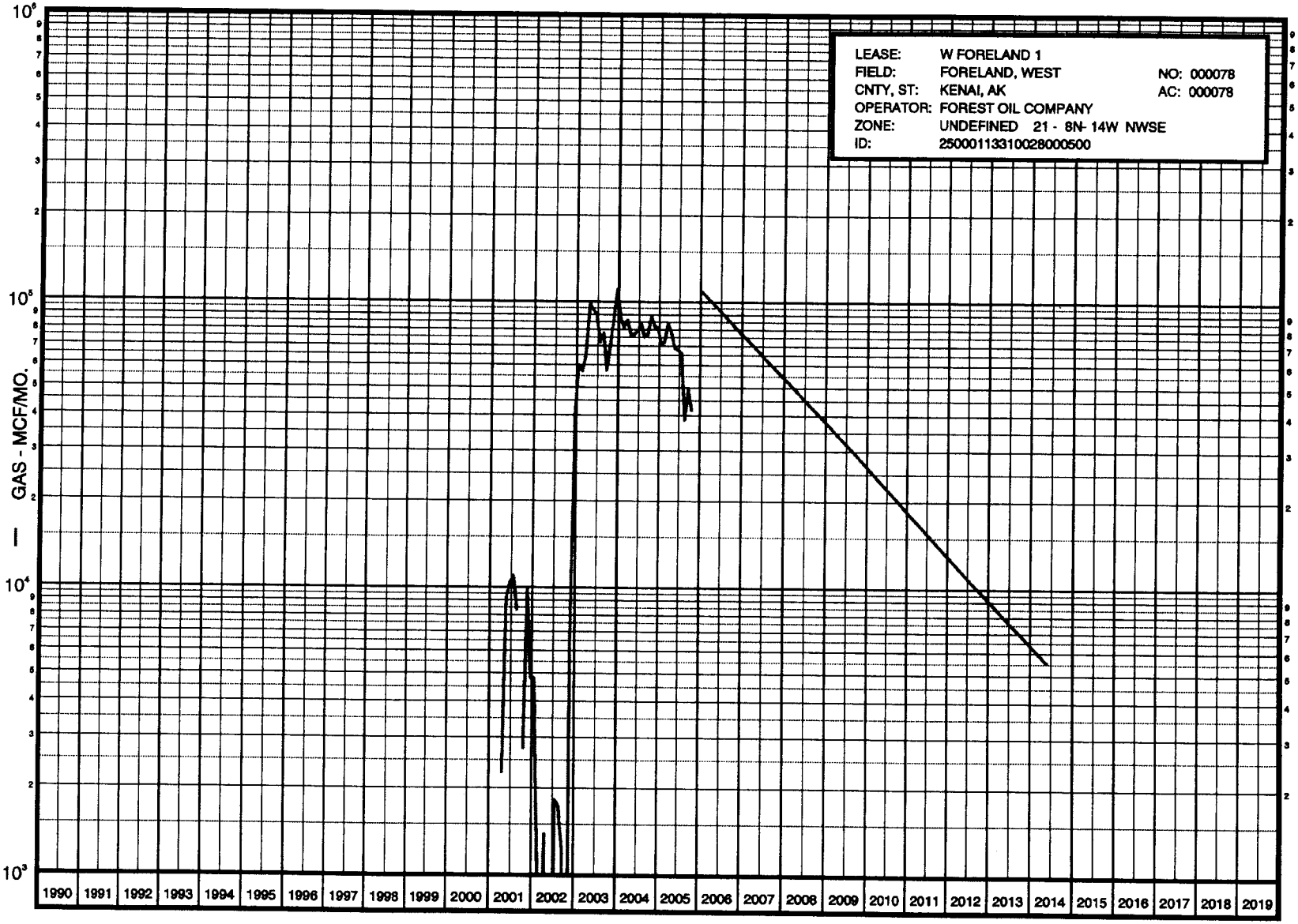

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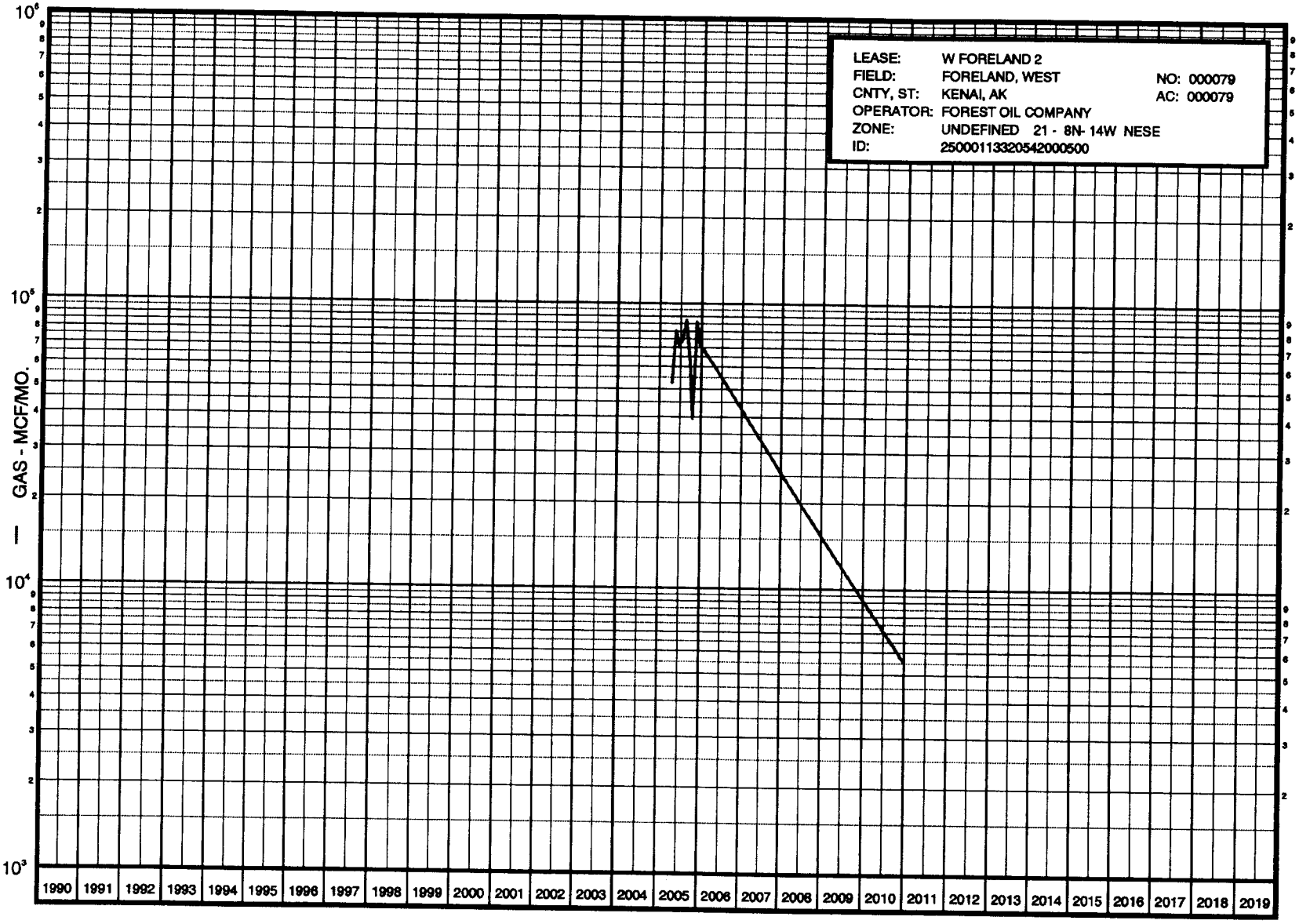

Figure 10.4.1.8

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

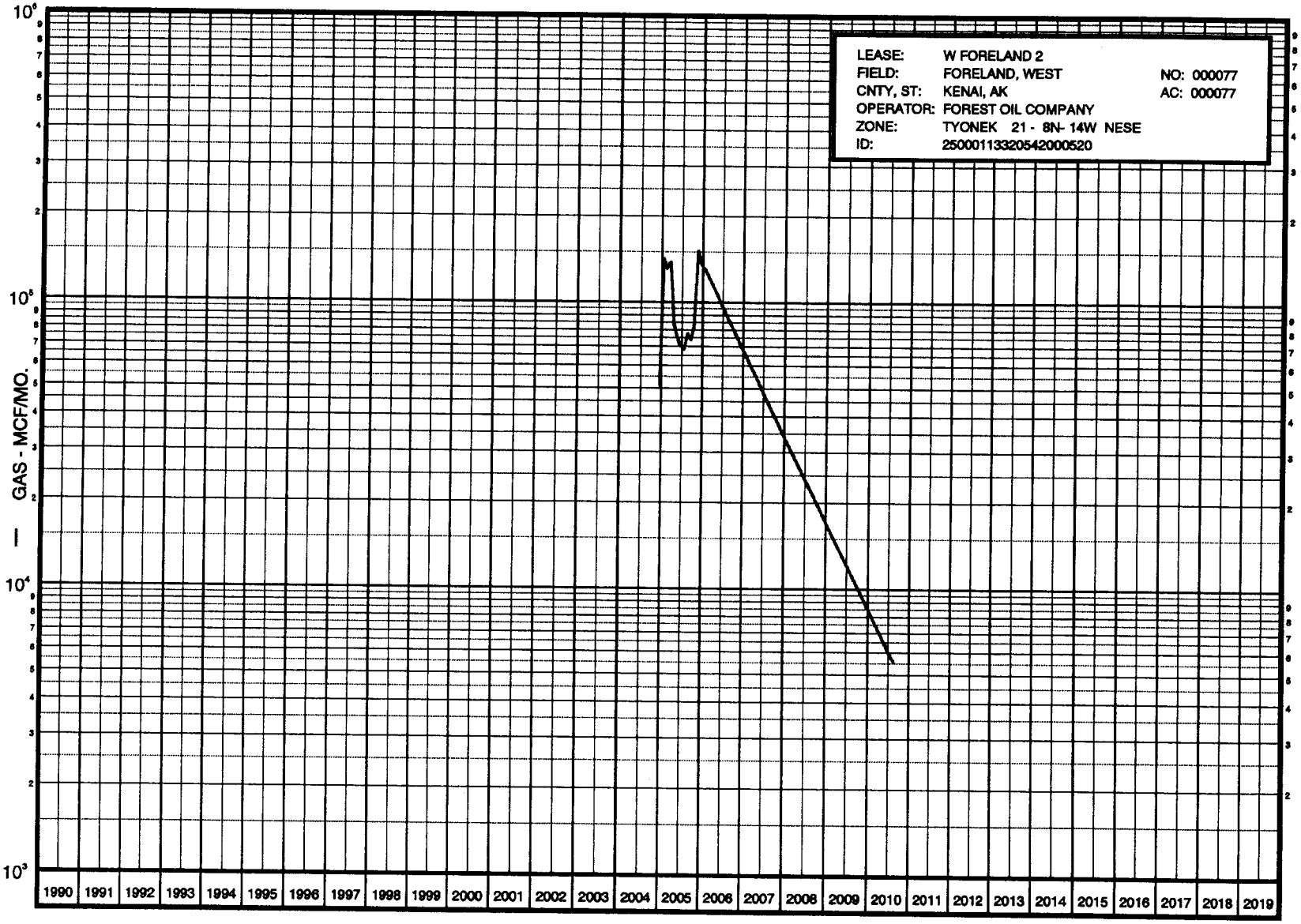

Figure 10.4.1.9

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

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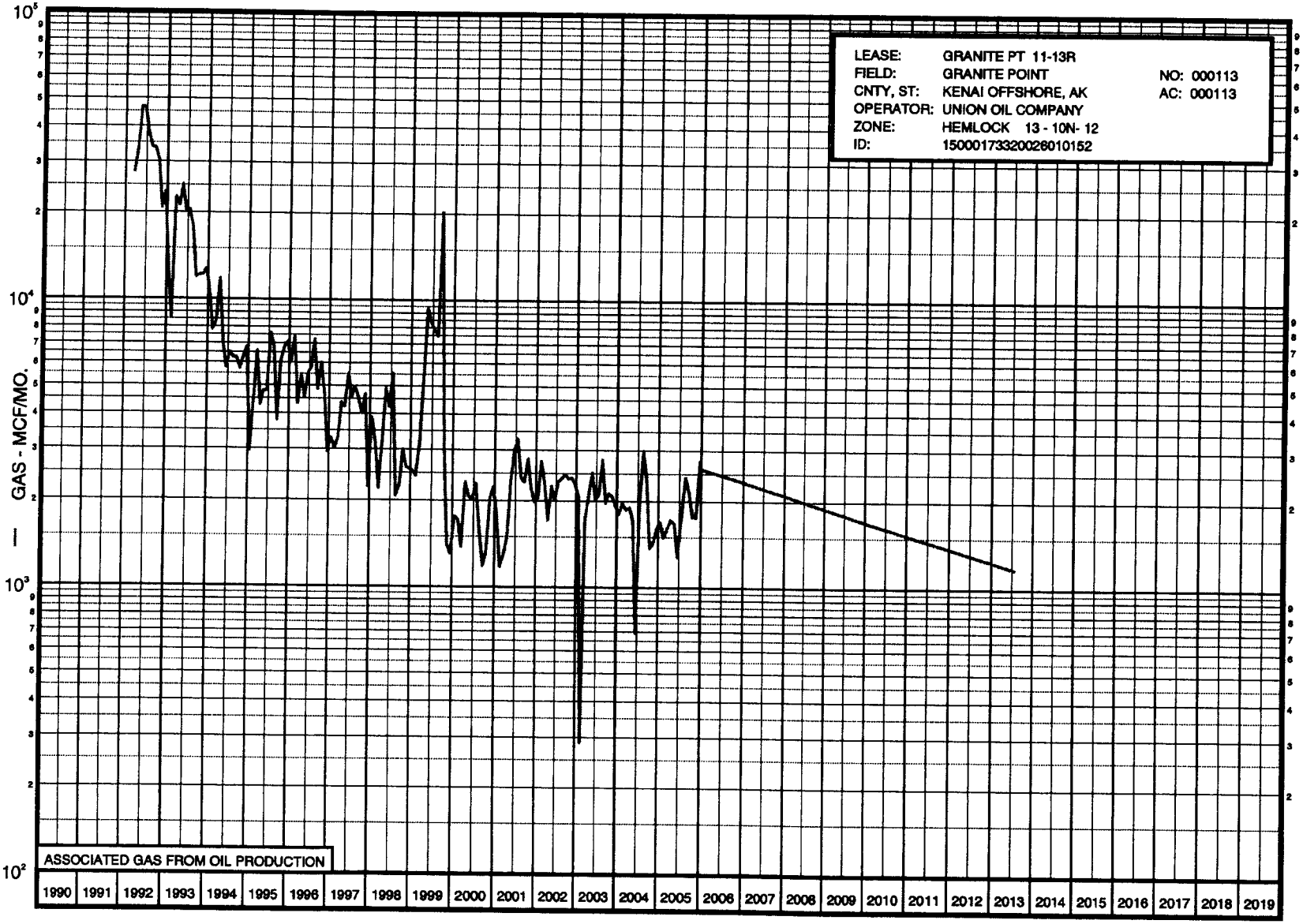

Figure 10.4.1.10

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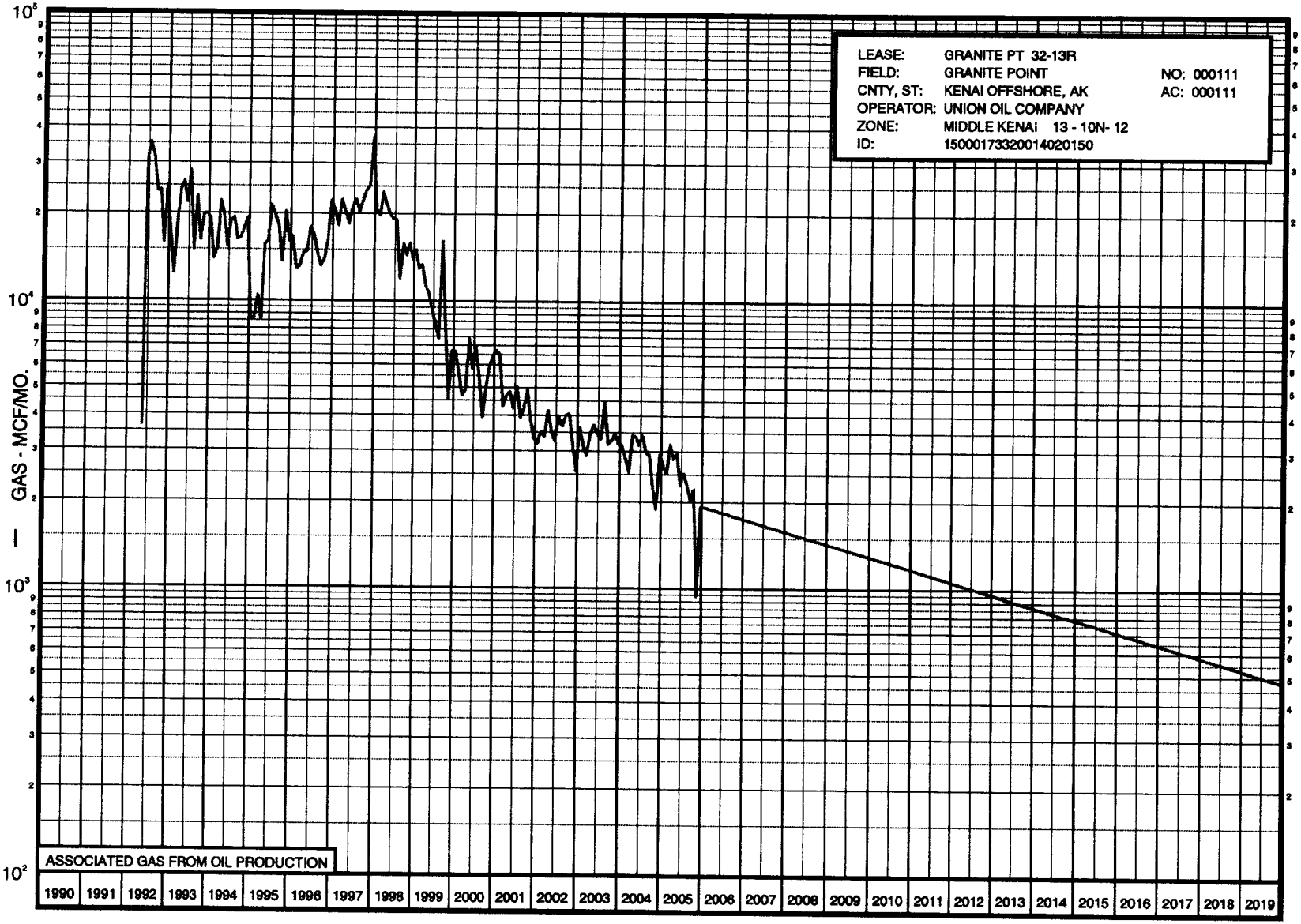

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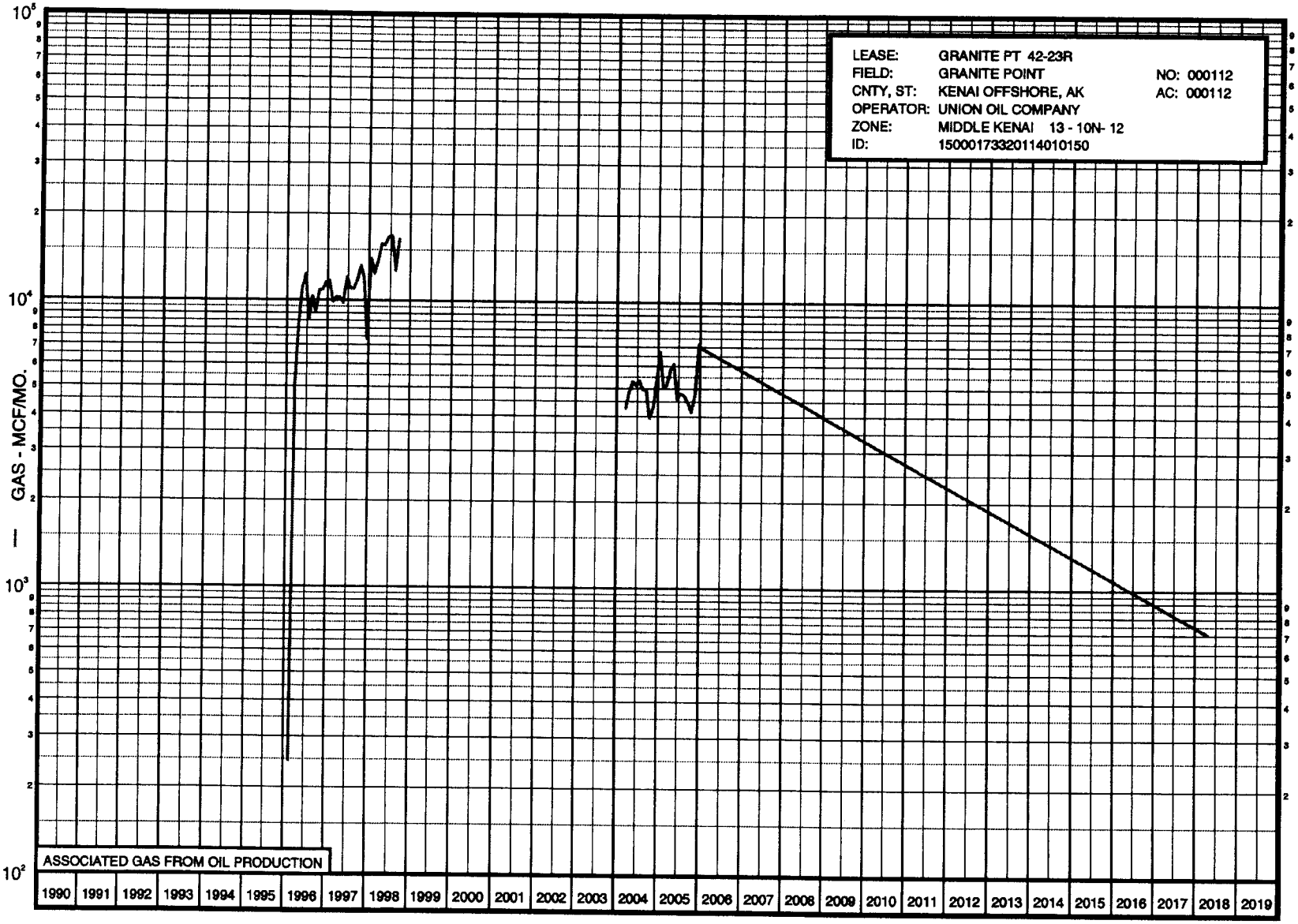

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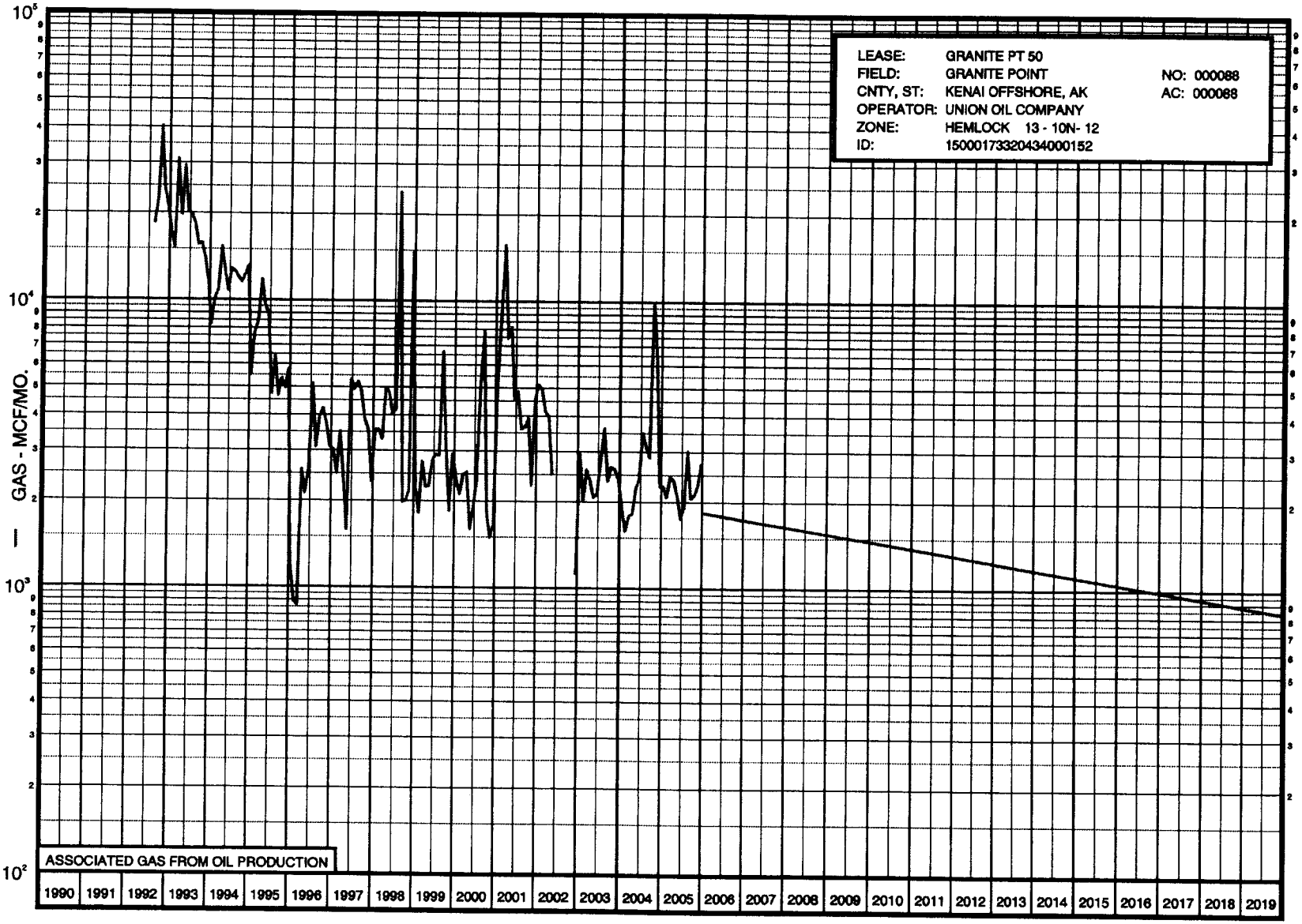
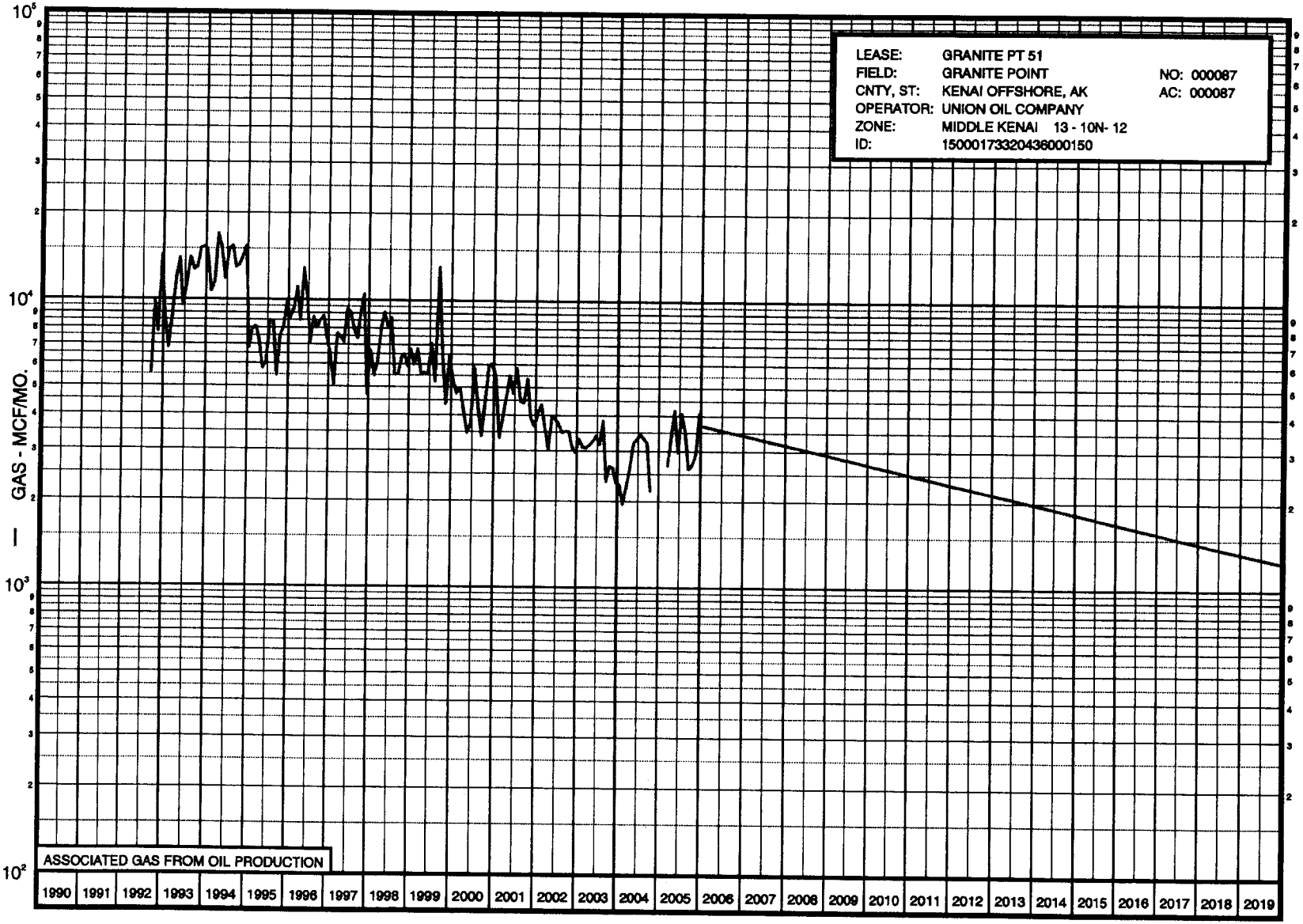


Figure 10.4.1.13

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.



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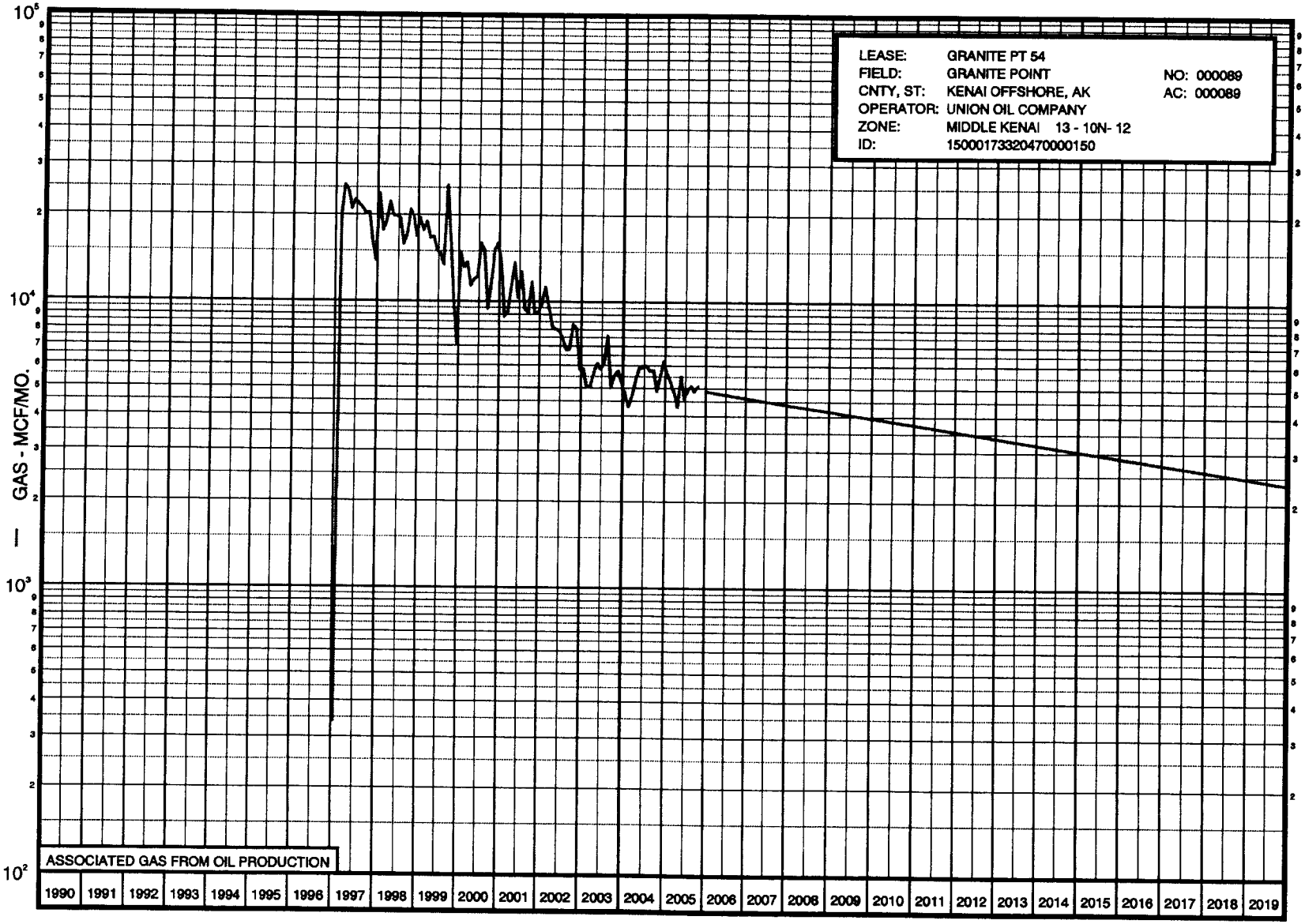

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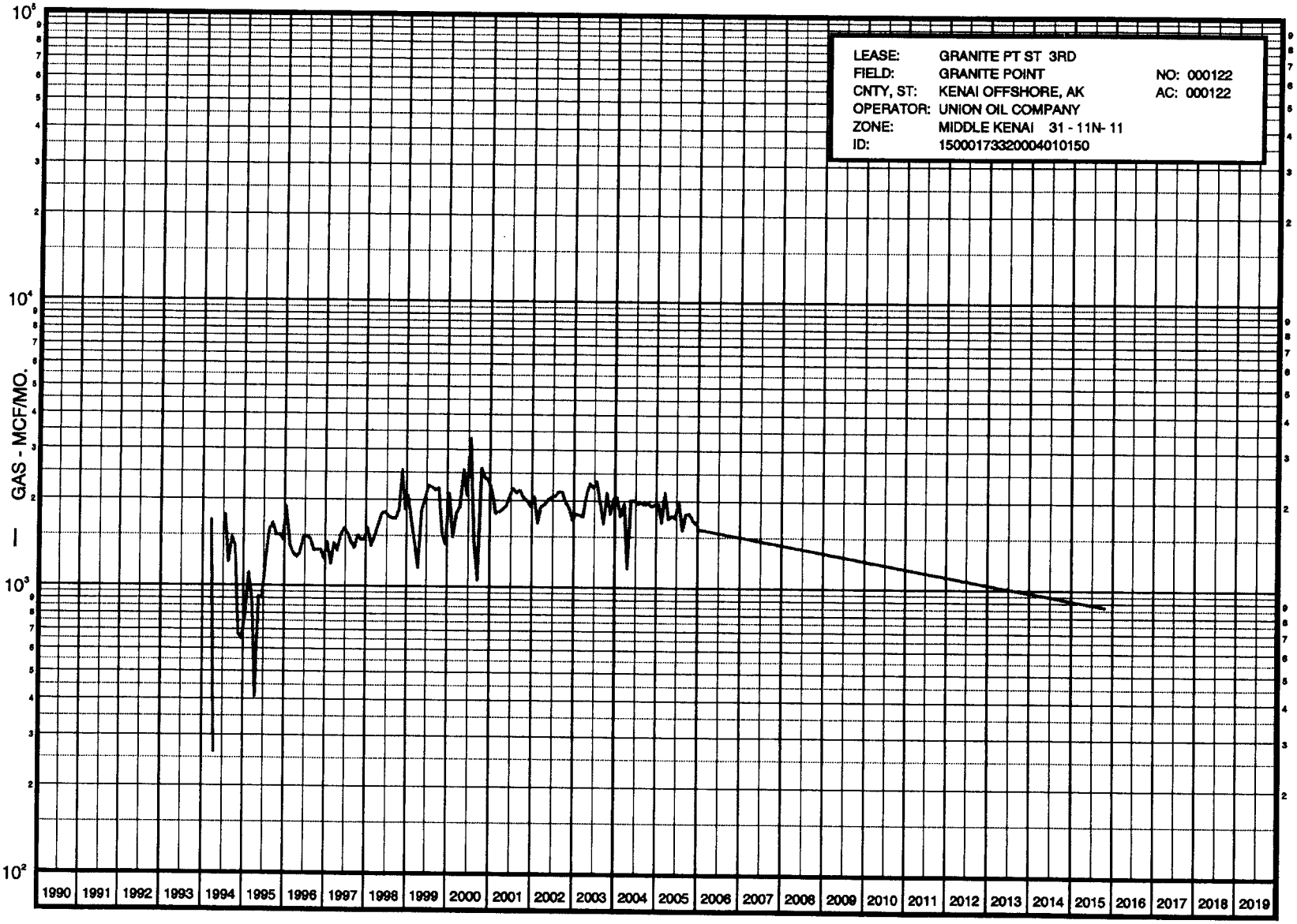

Figure 10.4.1.16

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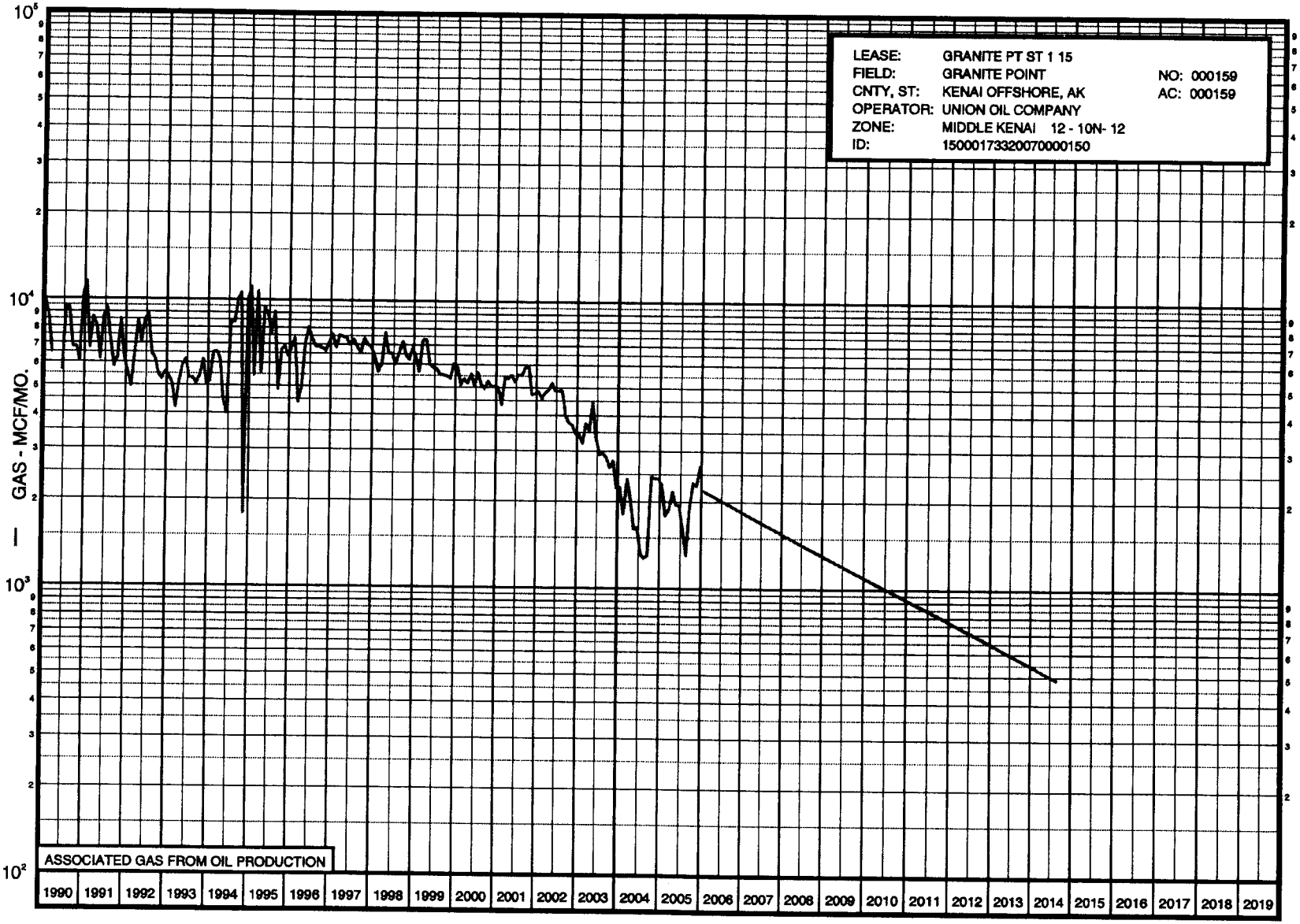
NETHERLAND, SEWELL & ASSOCIATES, INC.



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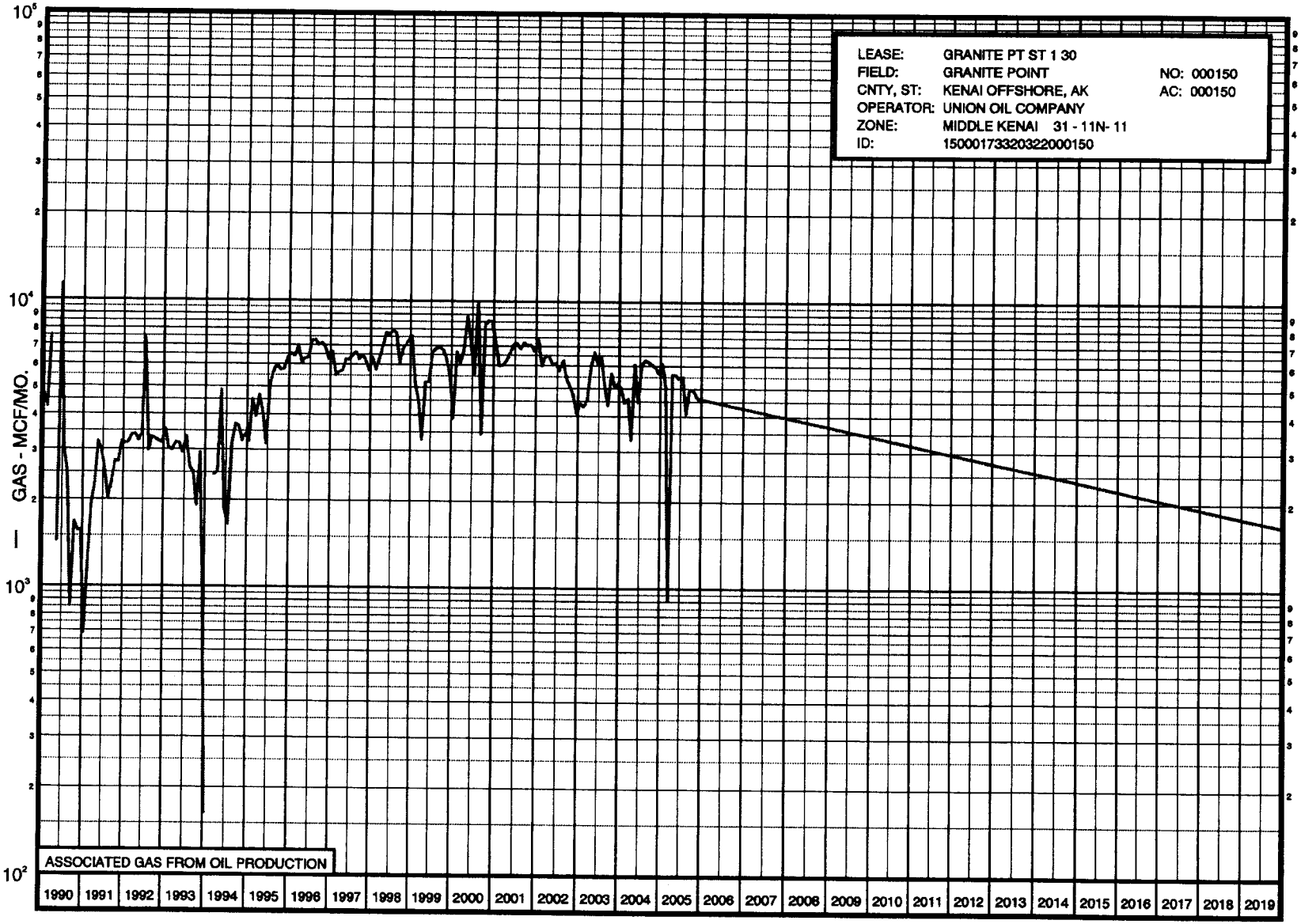

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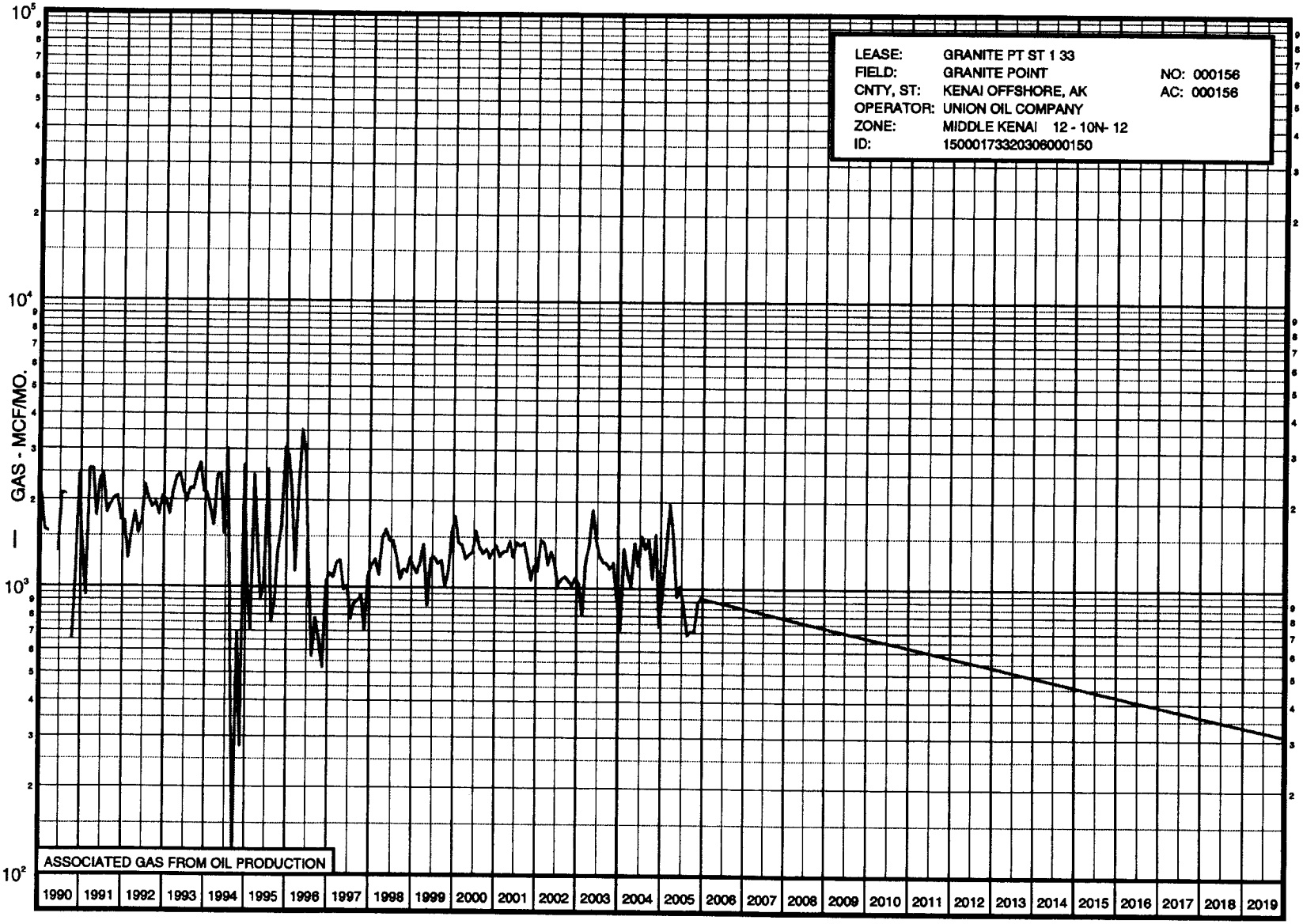

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NETHERLAND, SEWELL & ASSOCIATES, INC.

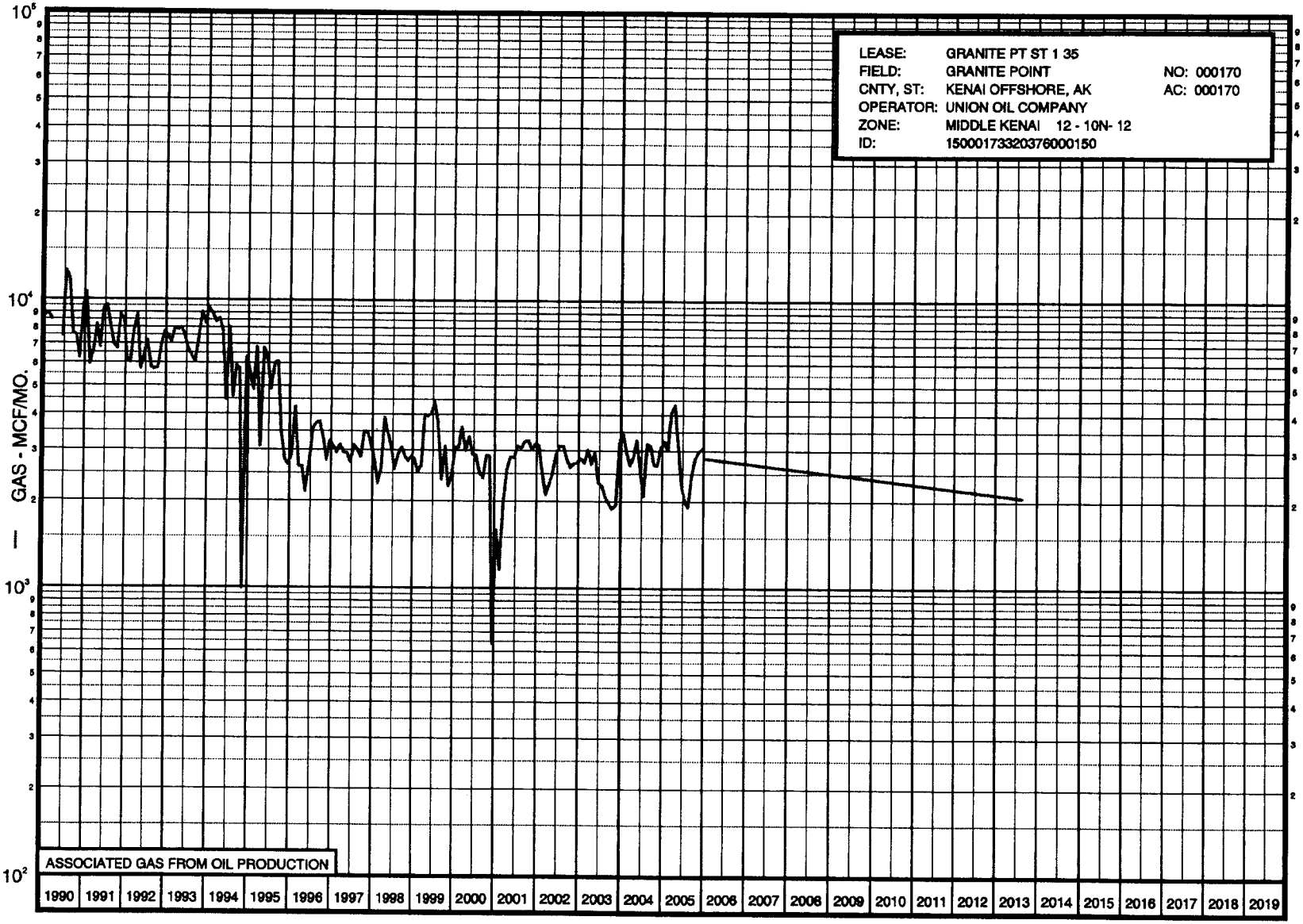

Figure 10.4.1.20

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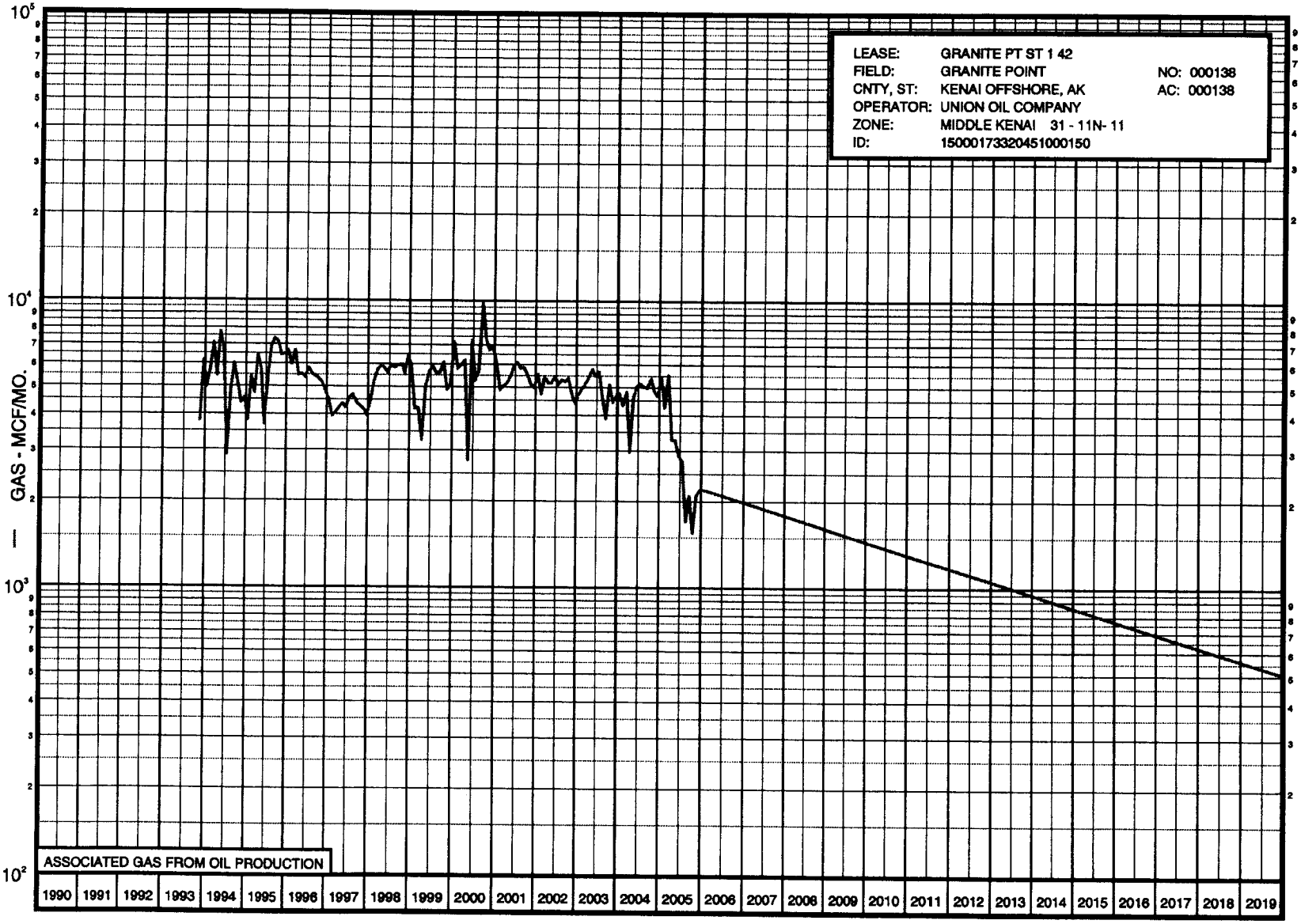

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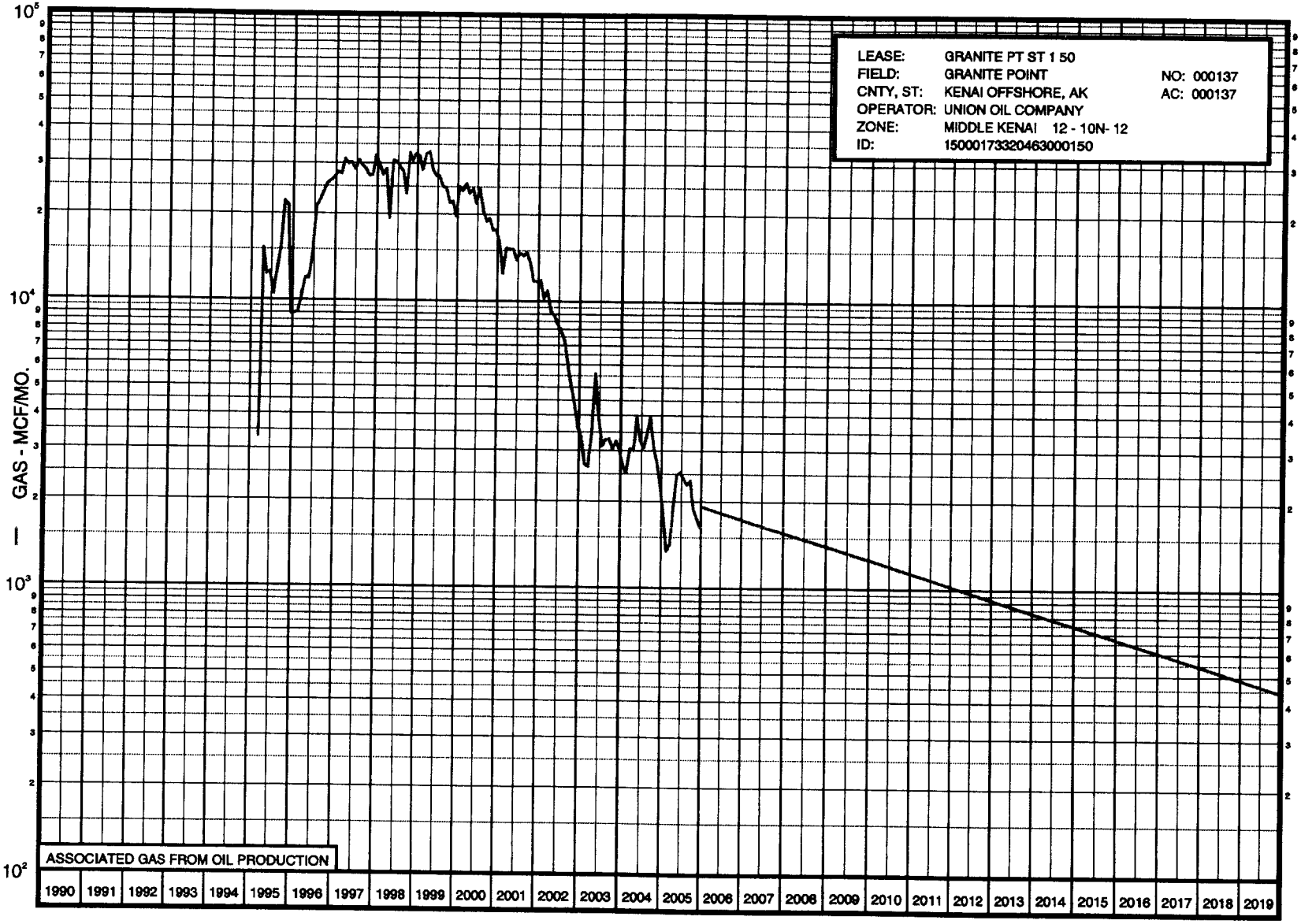

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NETHERLAND, SEWELL & ASSOCIATES, INC.

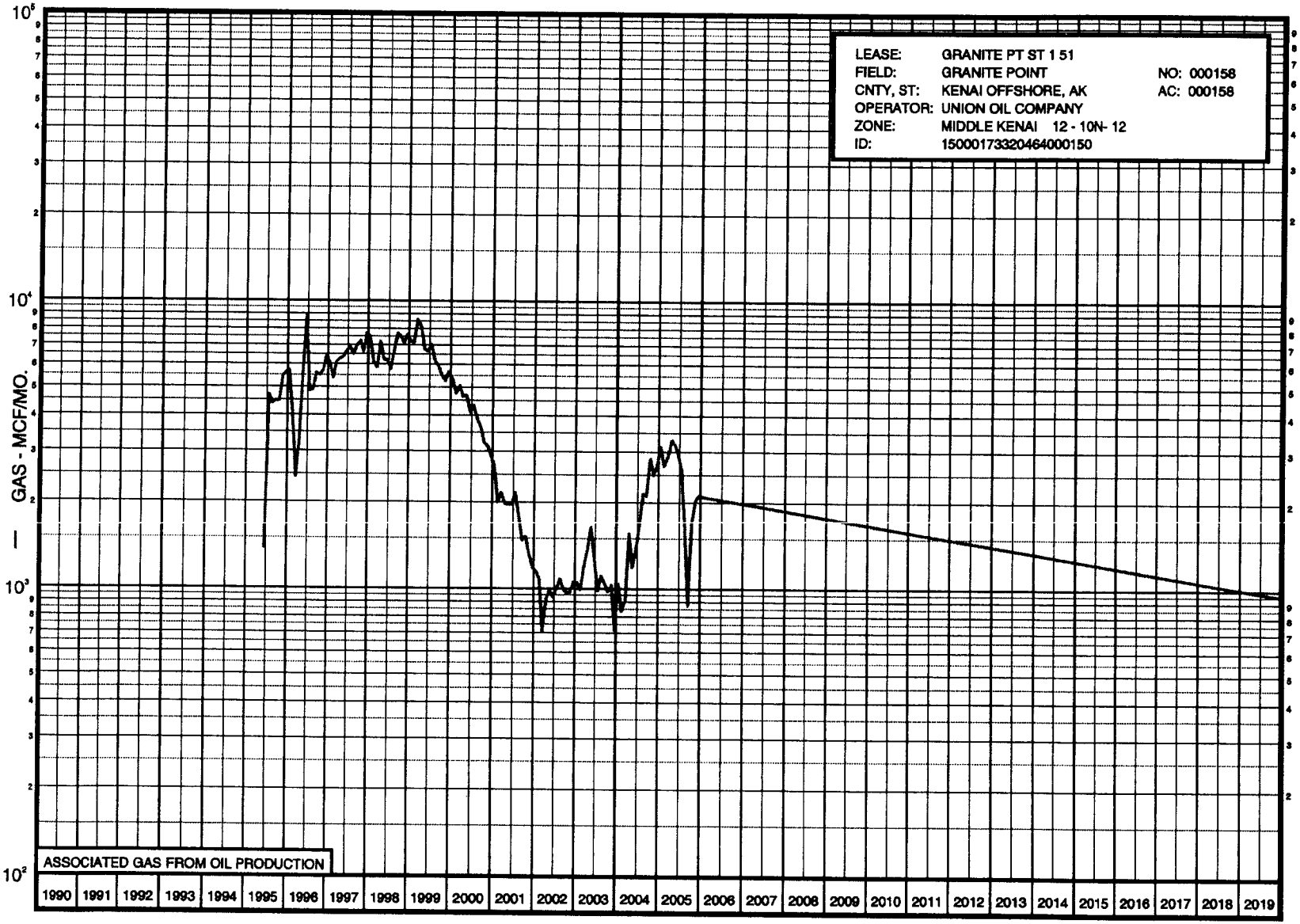

Figure 10.4.1.23

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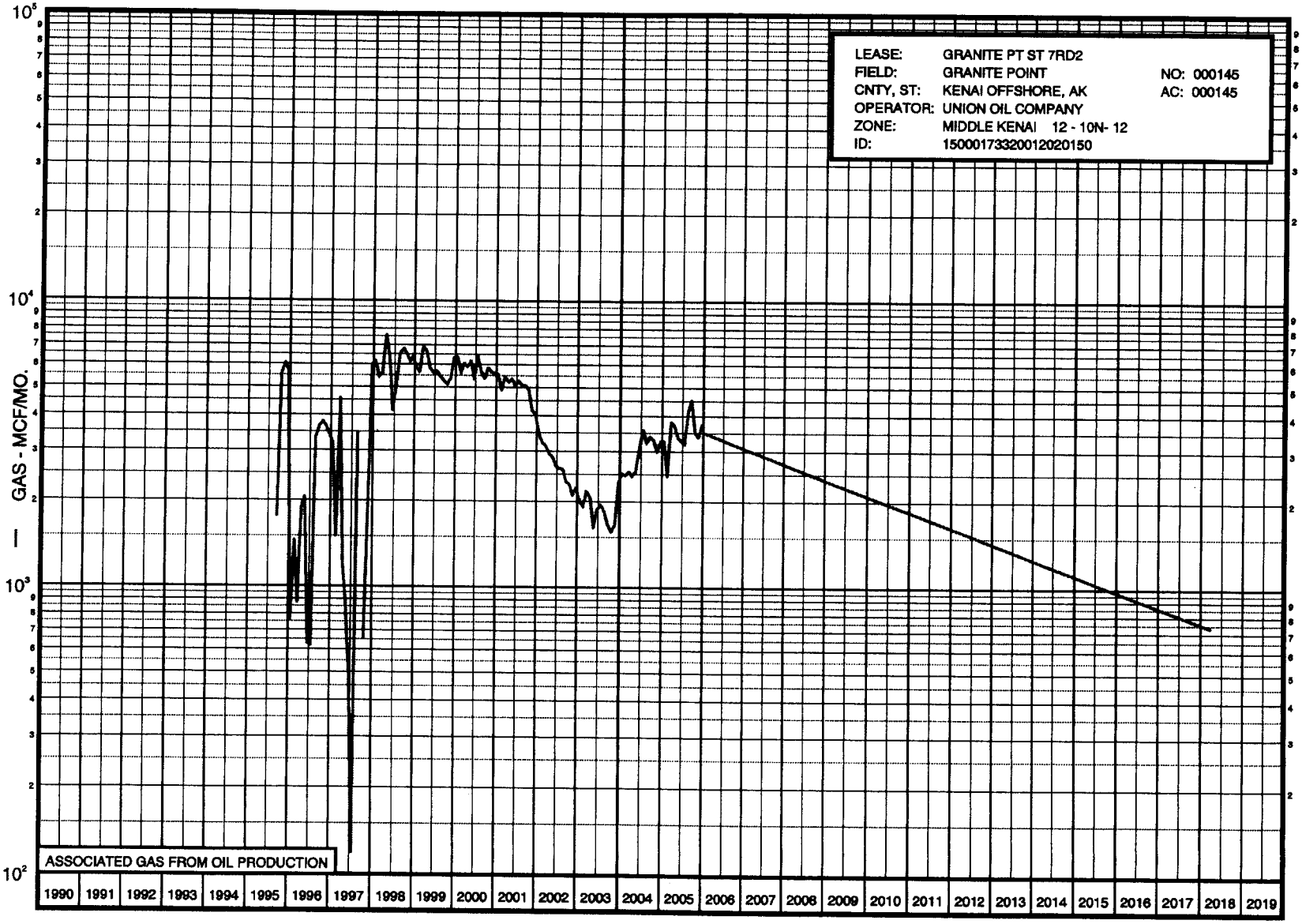

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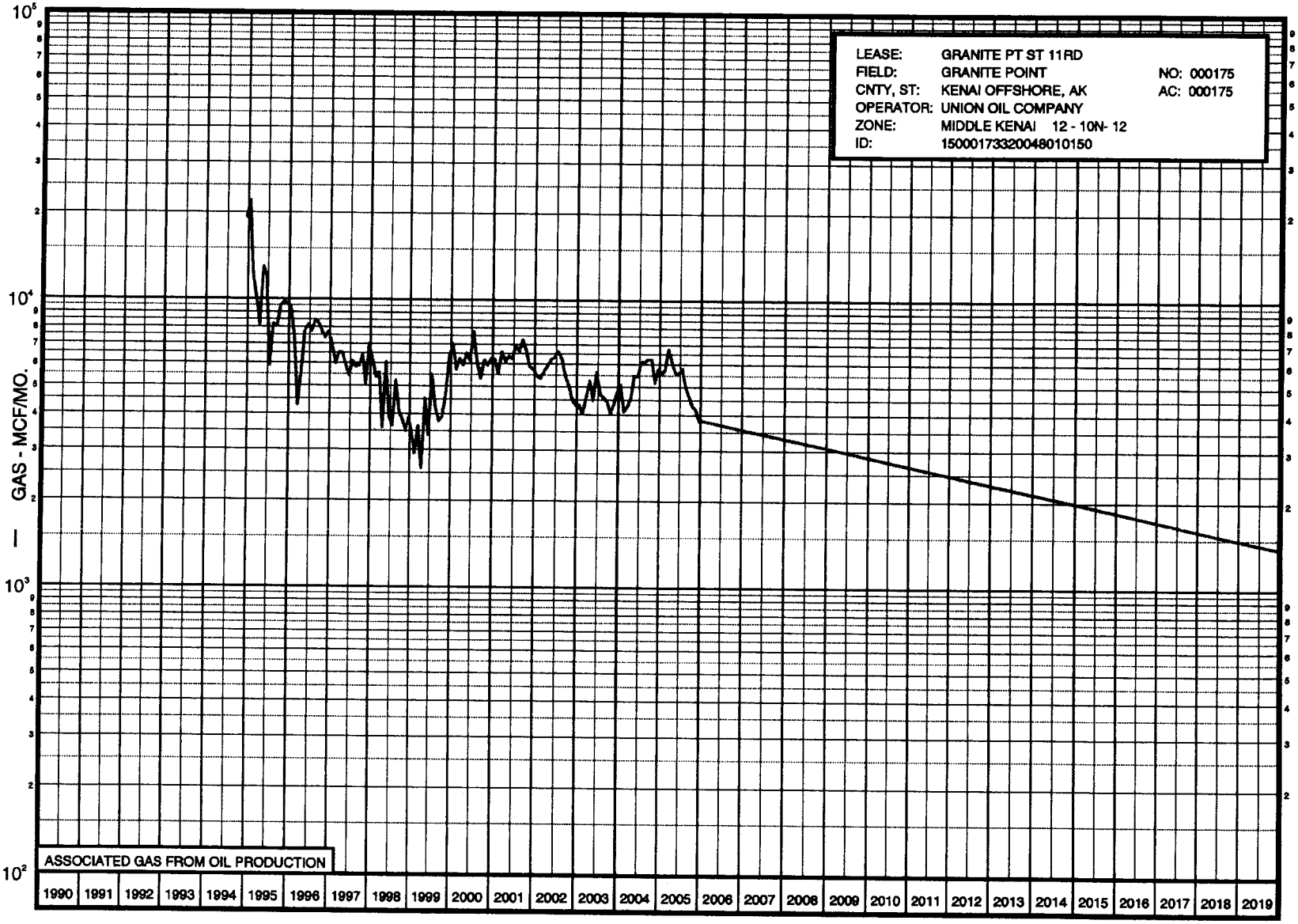

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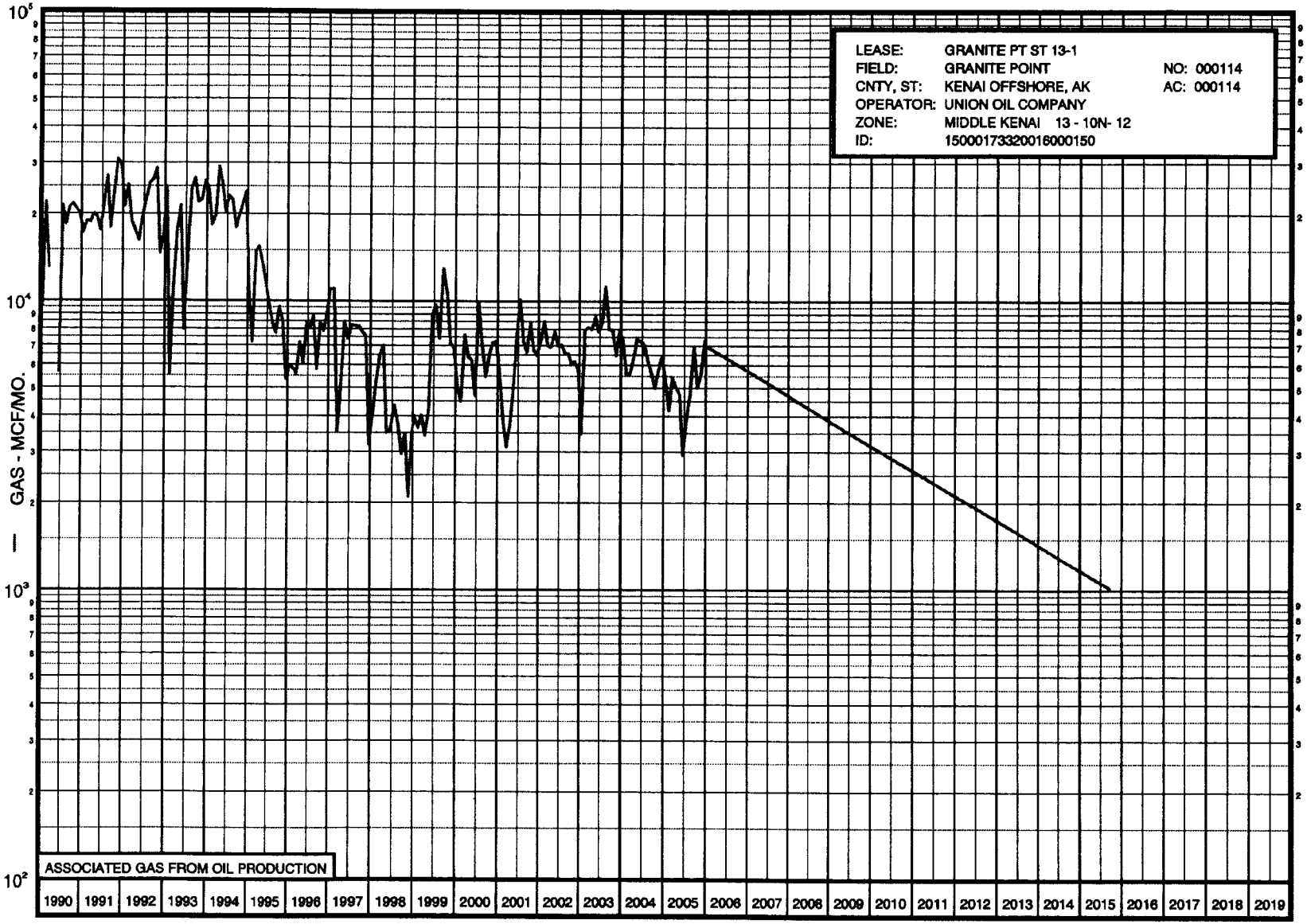

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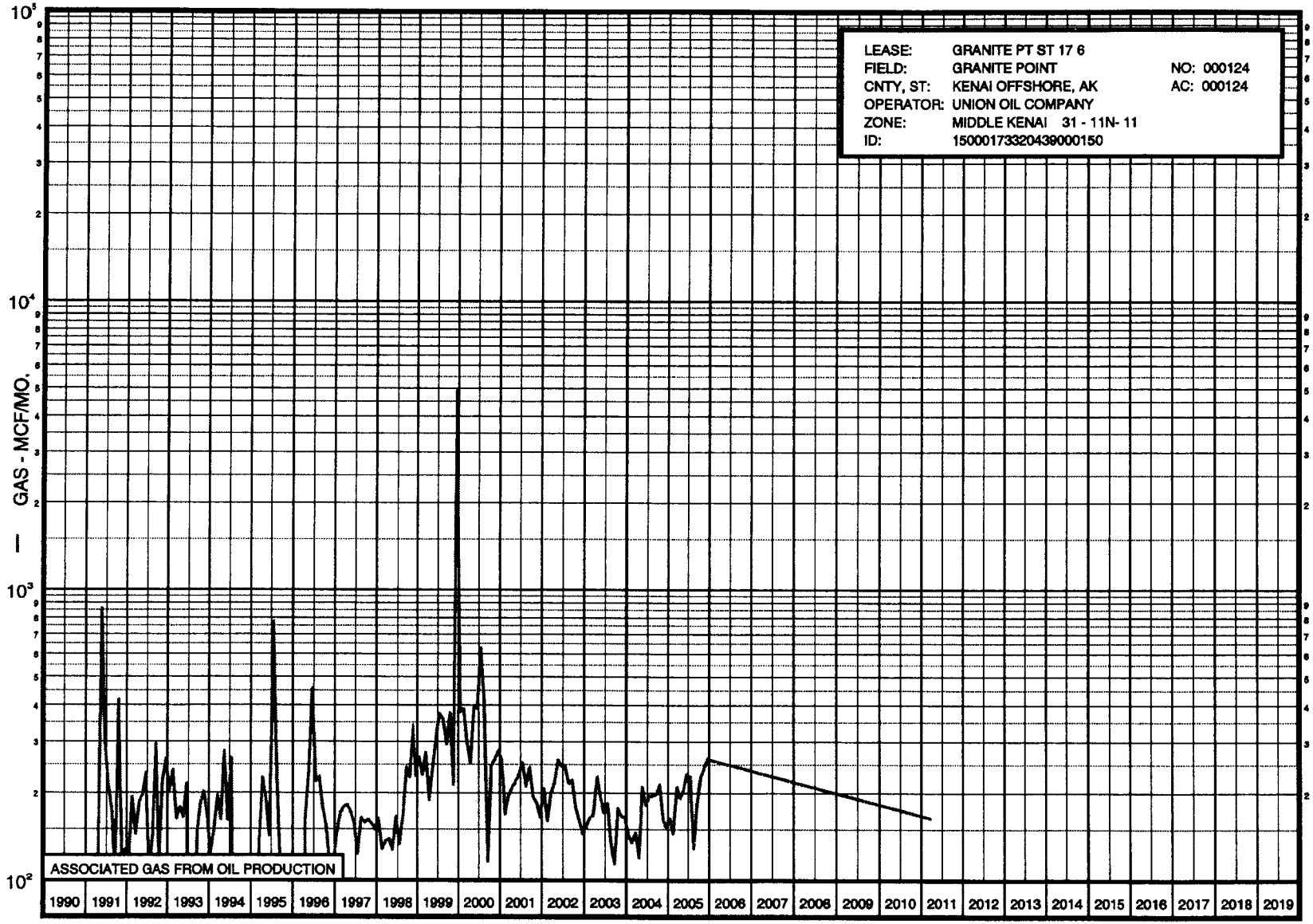
NETHERLAND, SEWELL & ASSOCIATES, INC.



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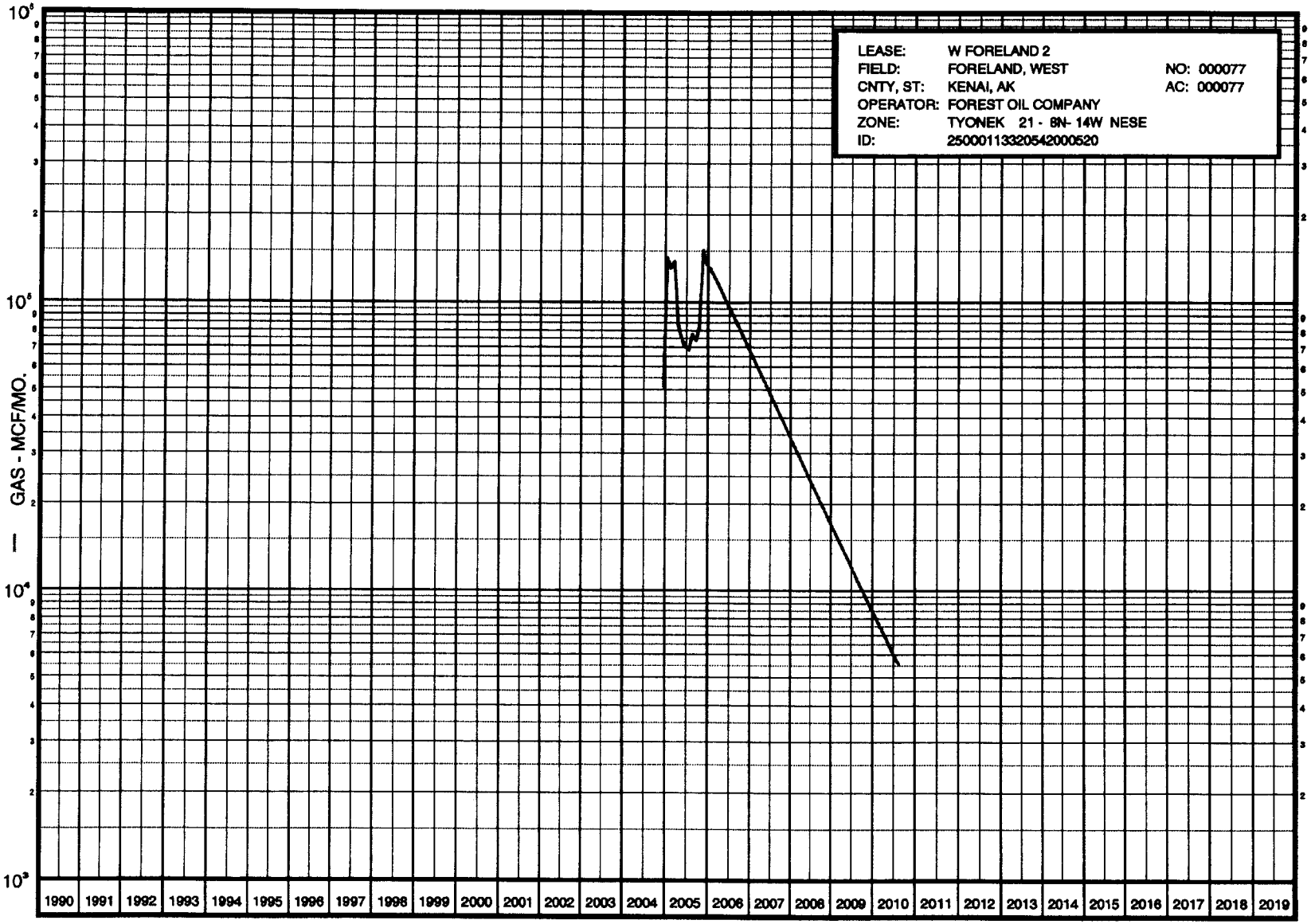

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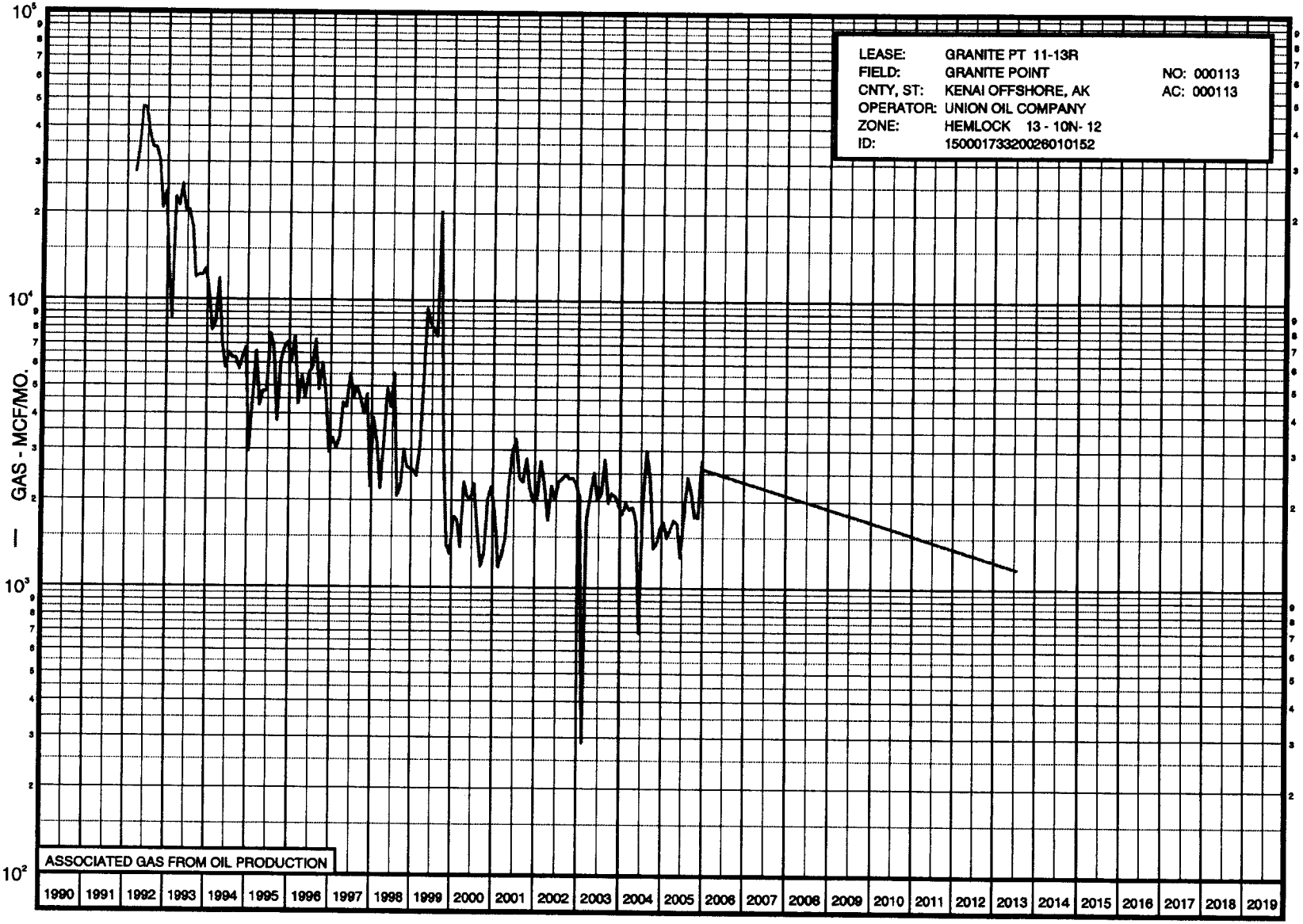

Figure 10.4.1.10

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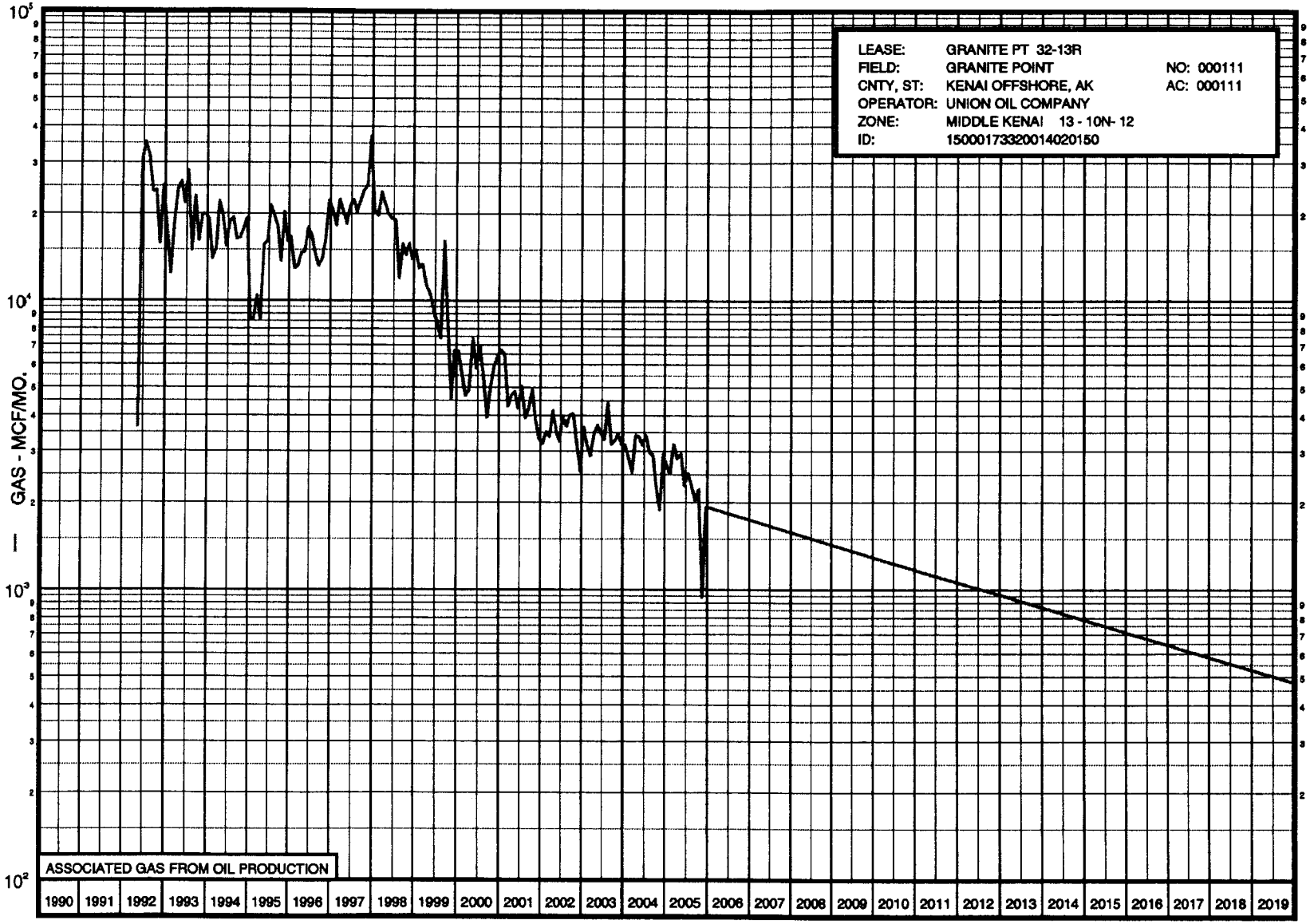

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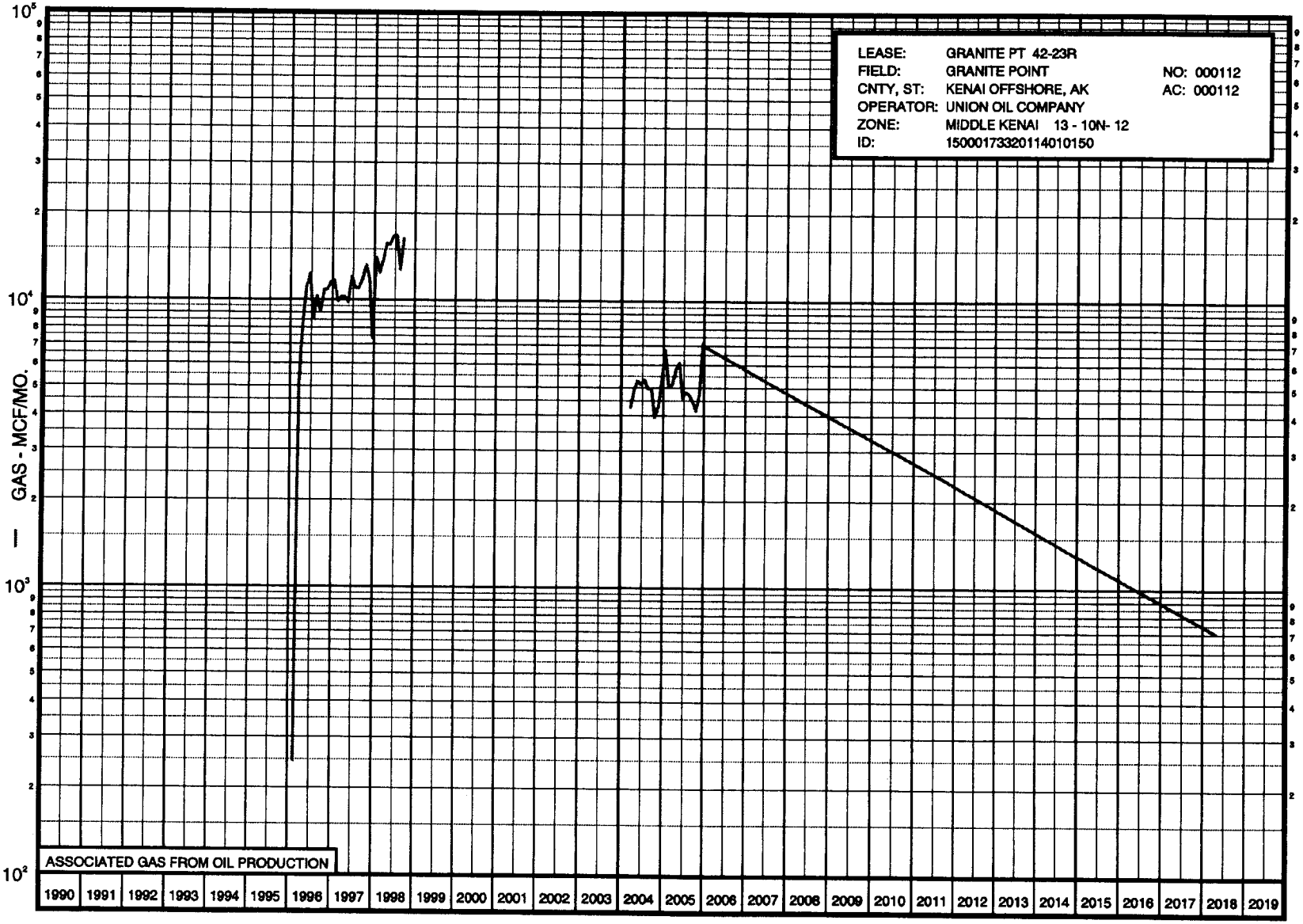

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NETHERLAND, SEWELL & ASSOCIATES, INC.

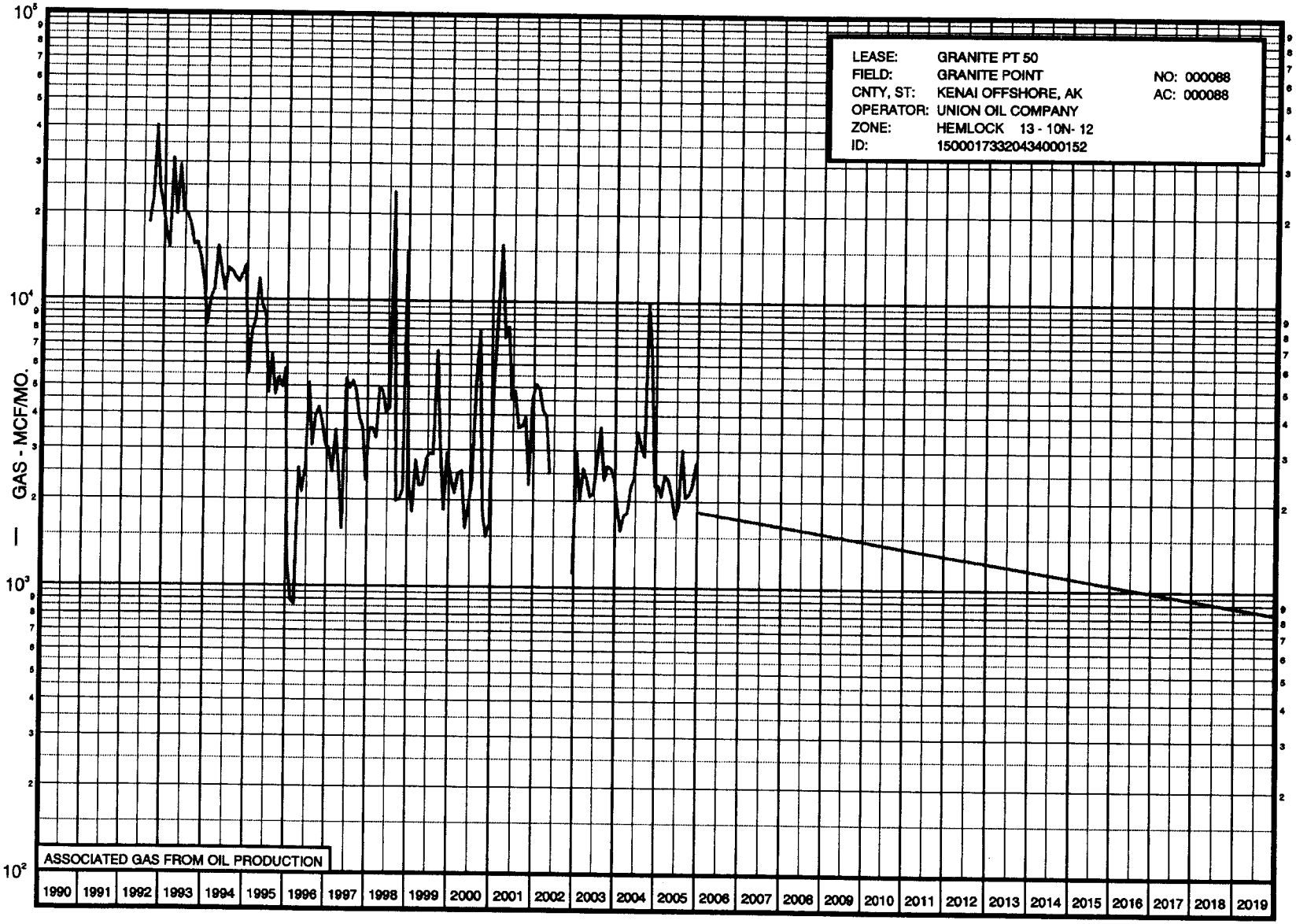

Figure 10.4.1.13

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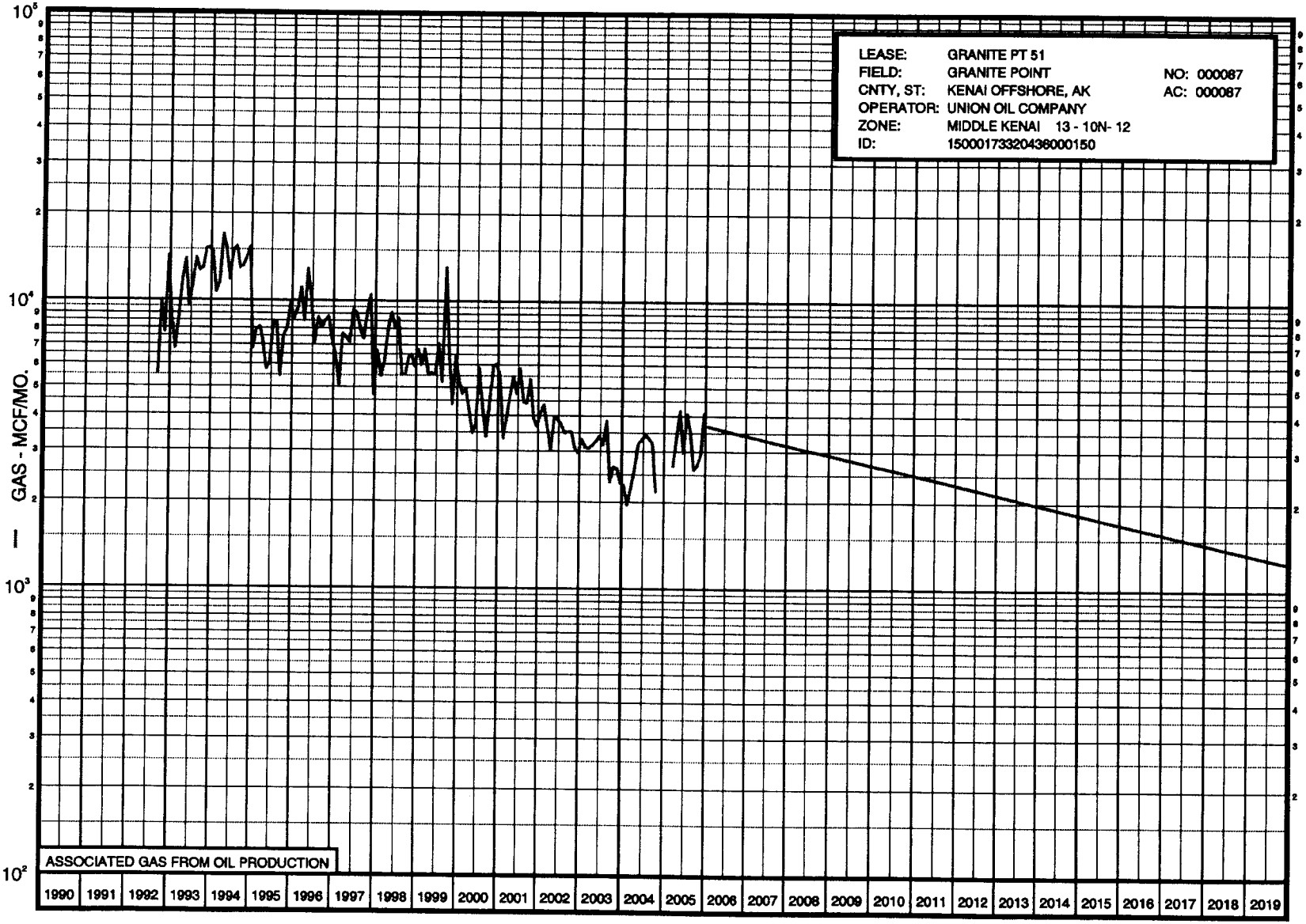

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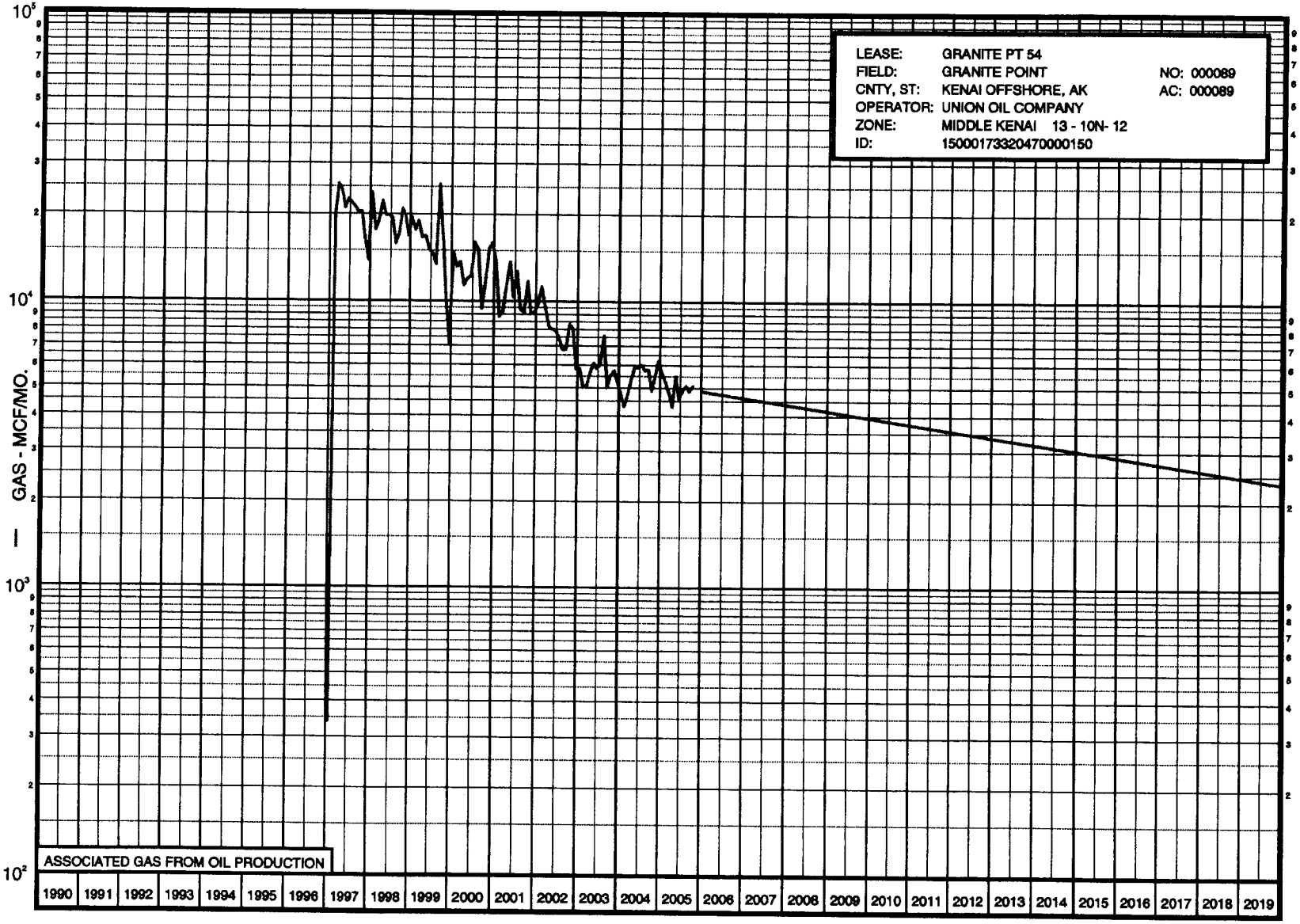

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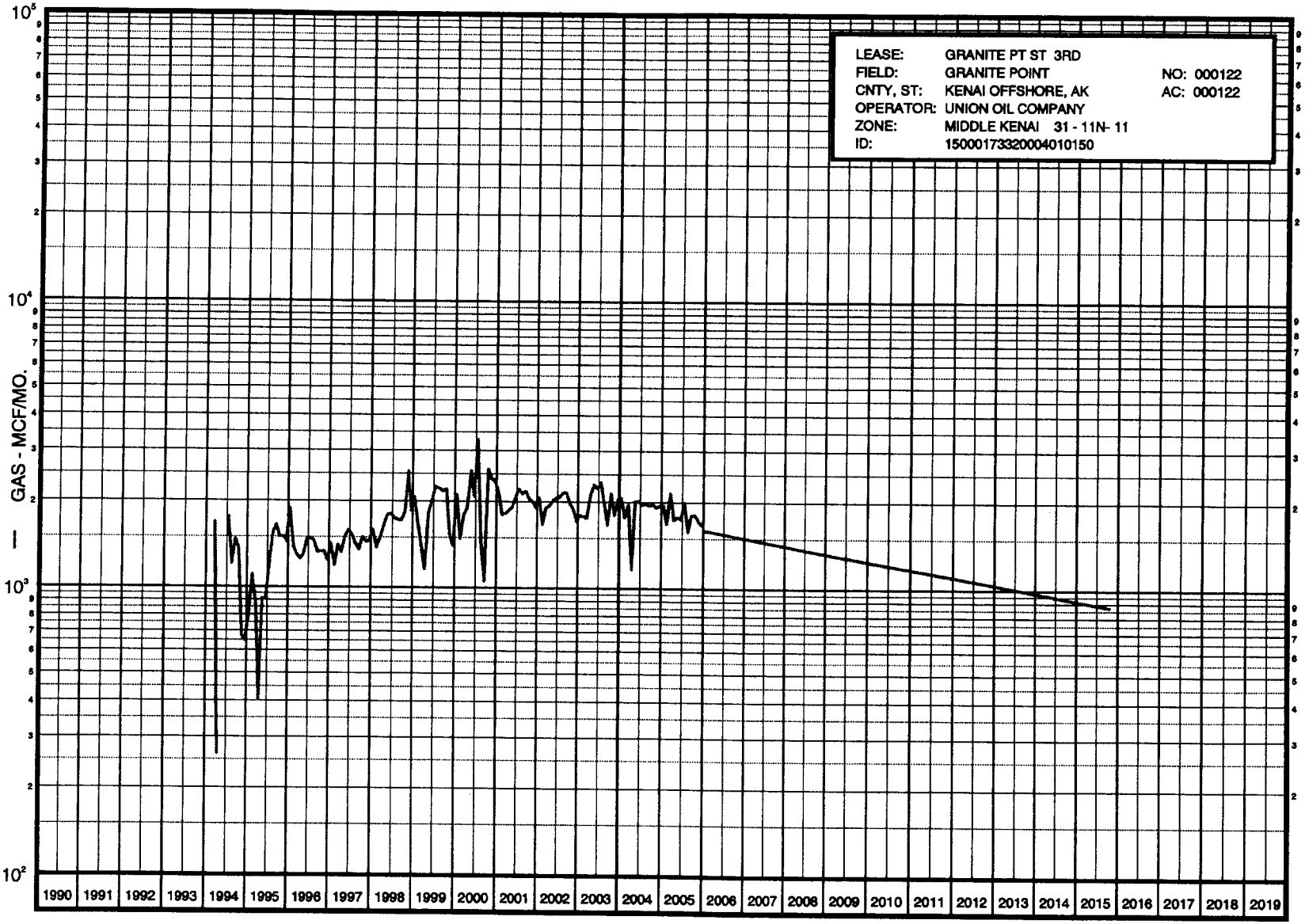
NETHERLAND, SEWELL & ASSOCIATES, INC.



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NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

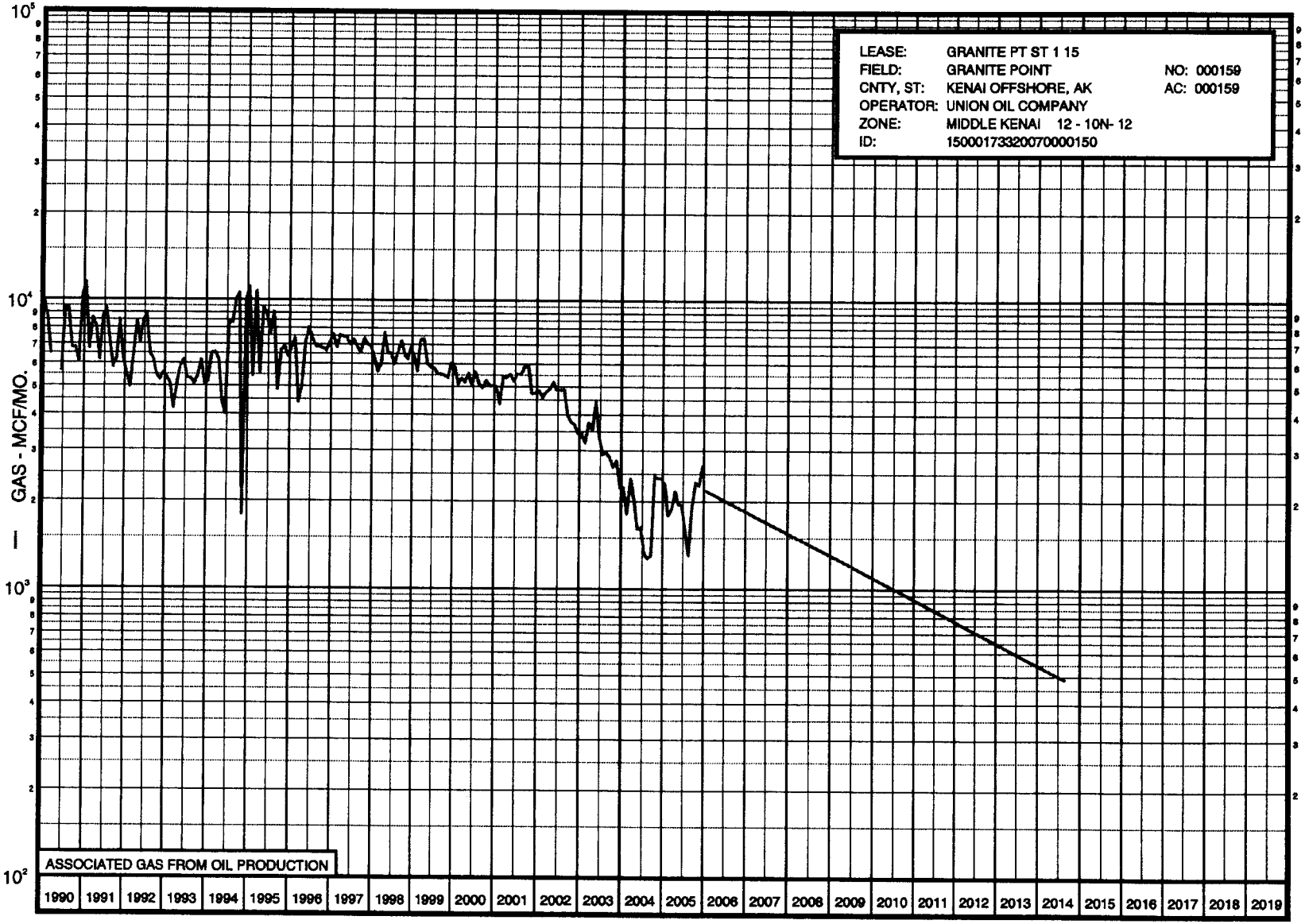

Figure 10.4.1.17

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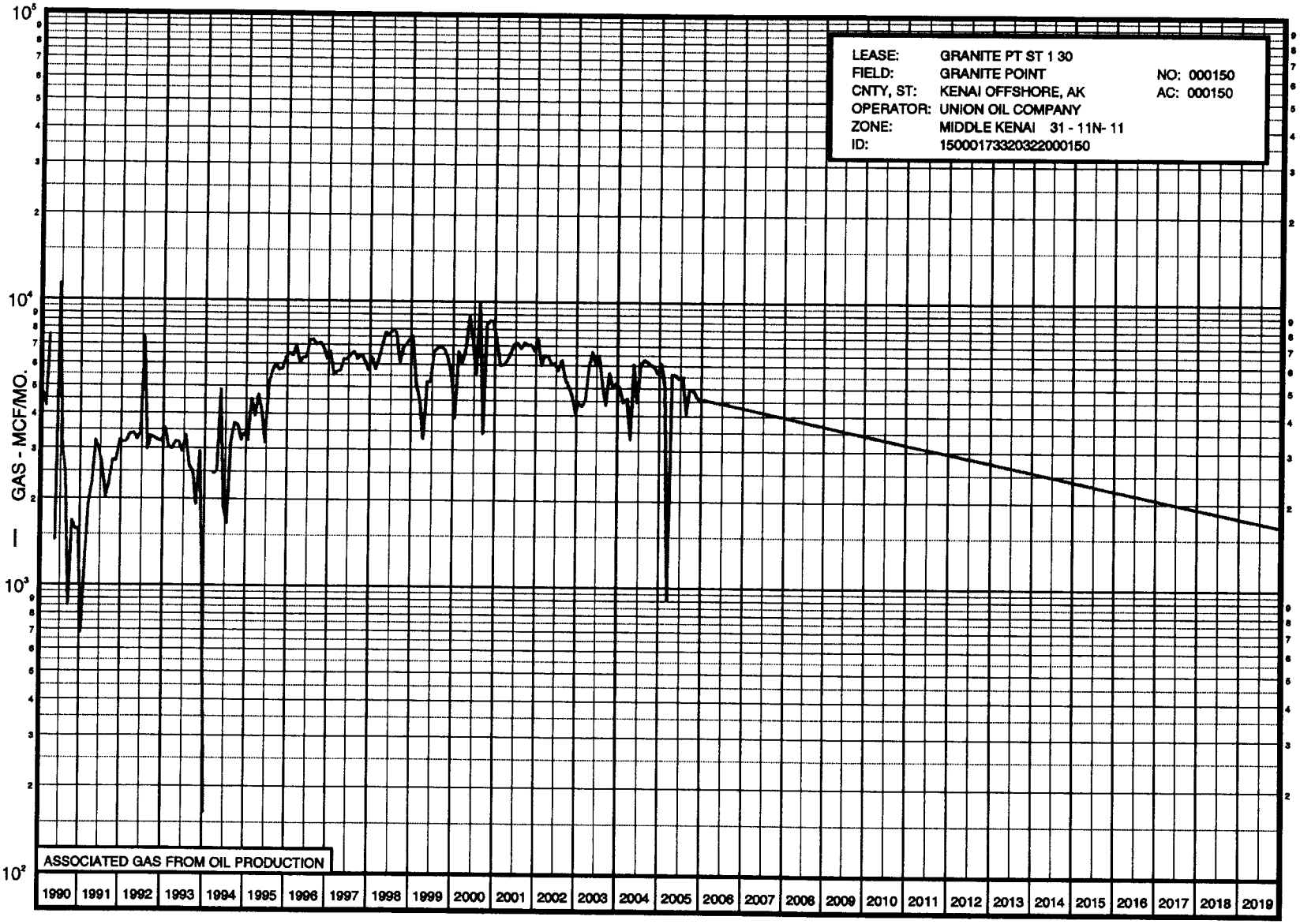

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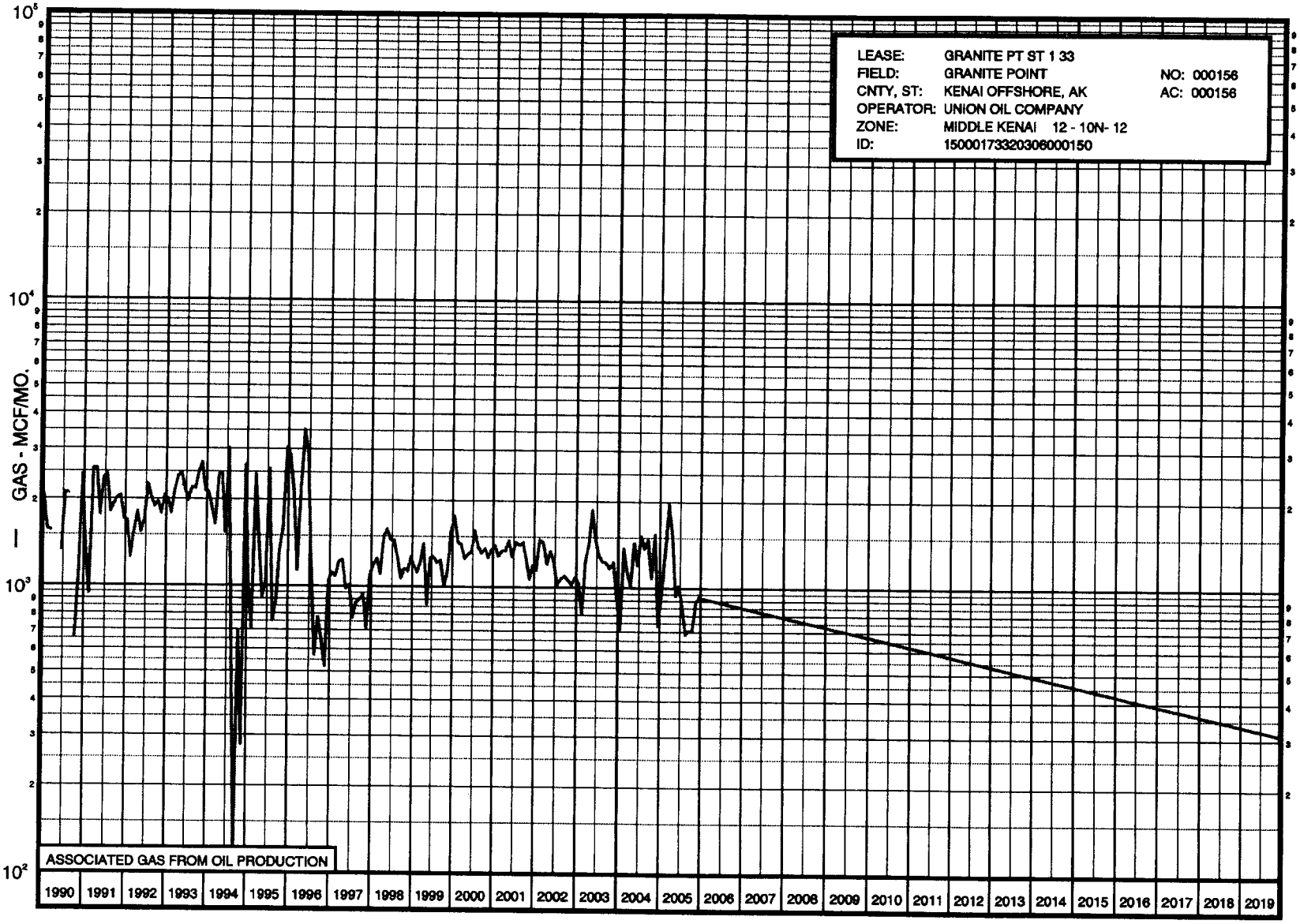

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NETHERLAND, SEWELL & ASSOCIATES, INC.

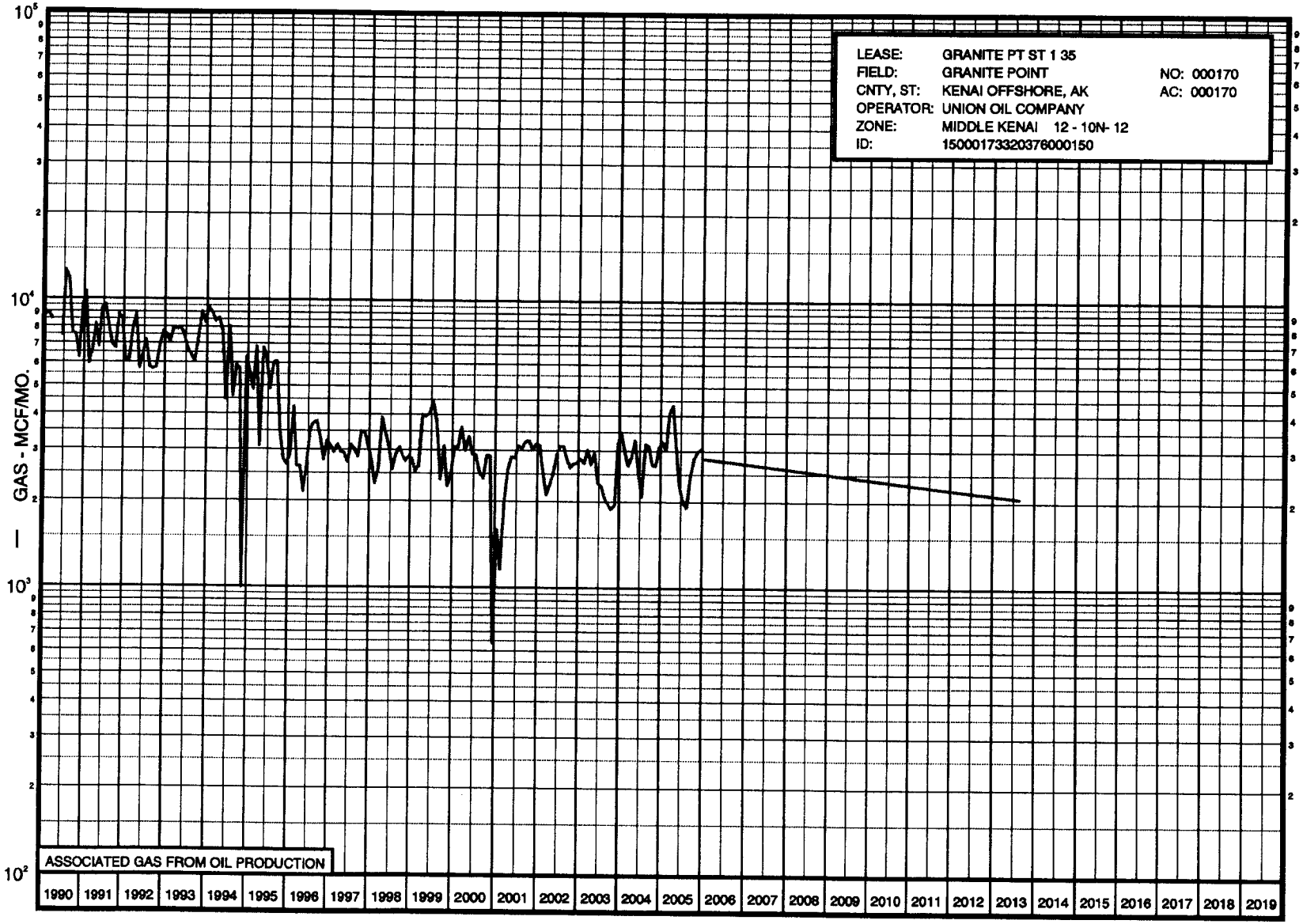

Figure 10.4.1.20

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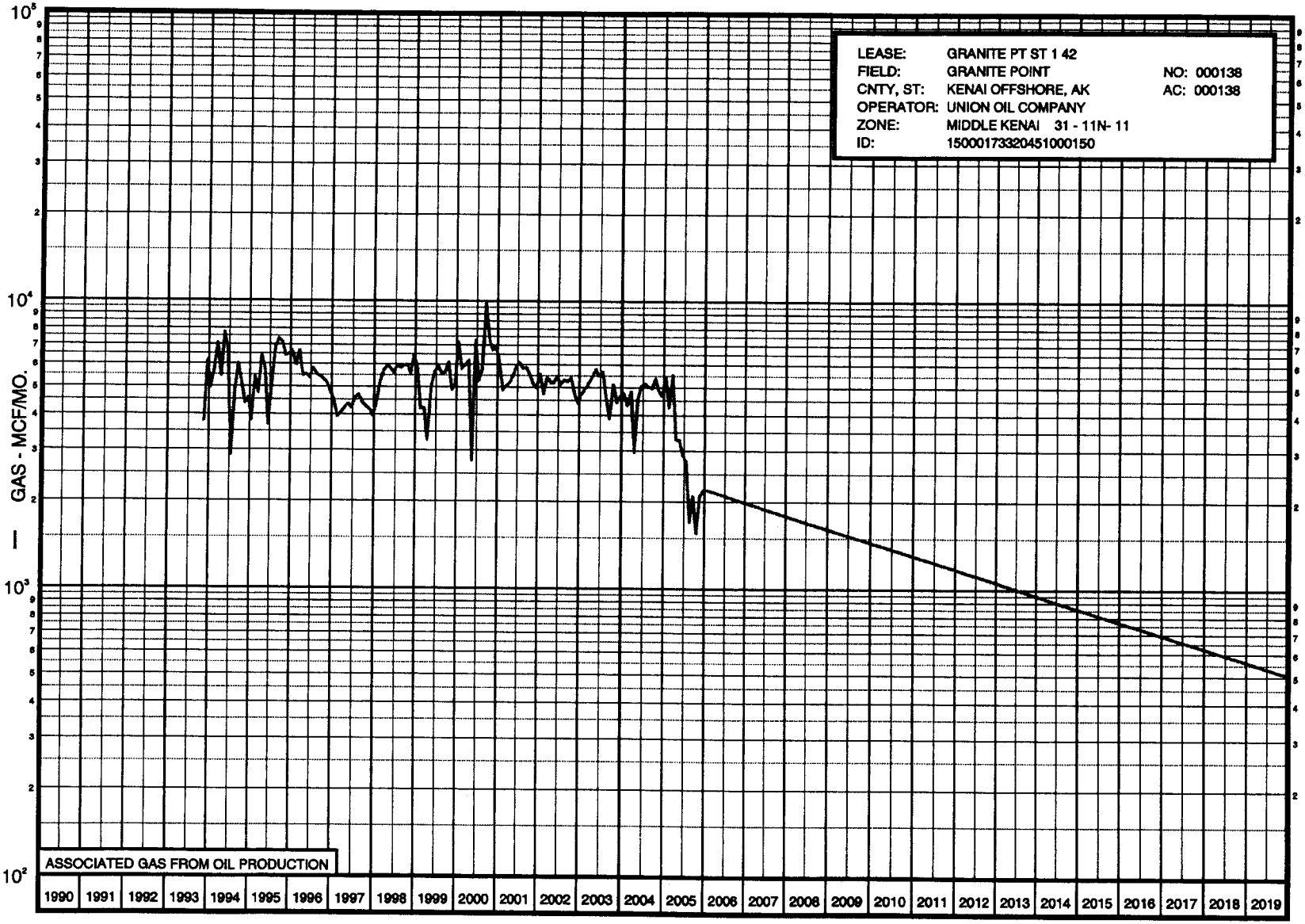
NETHERLAND, SEWELL & ASSOCIATES, INC.



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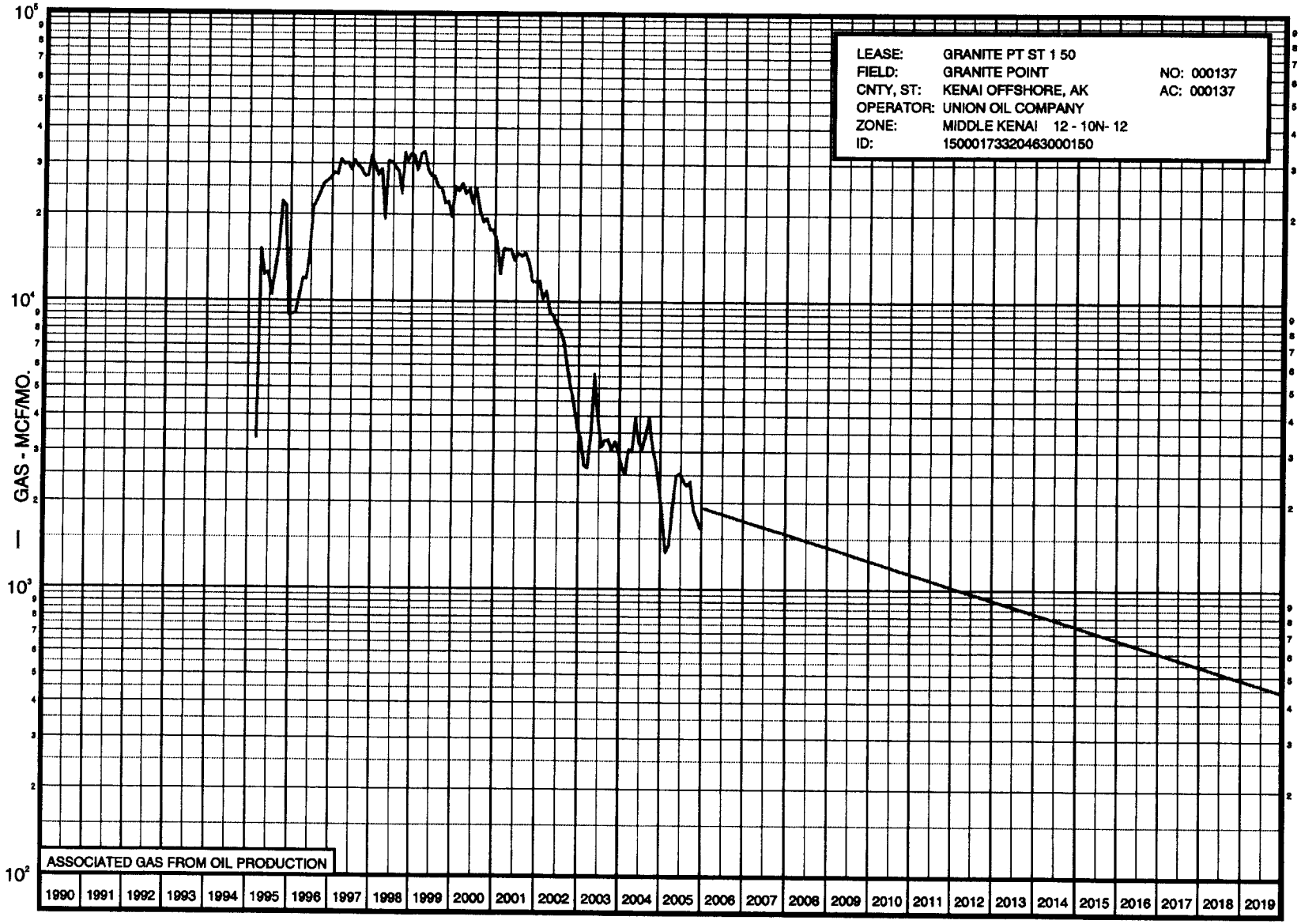

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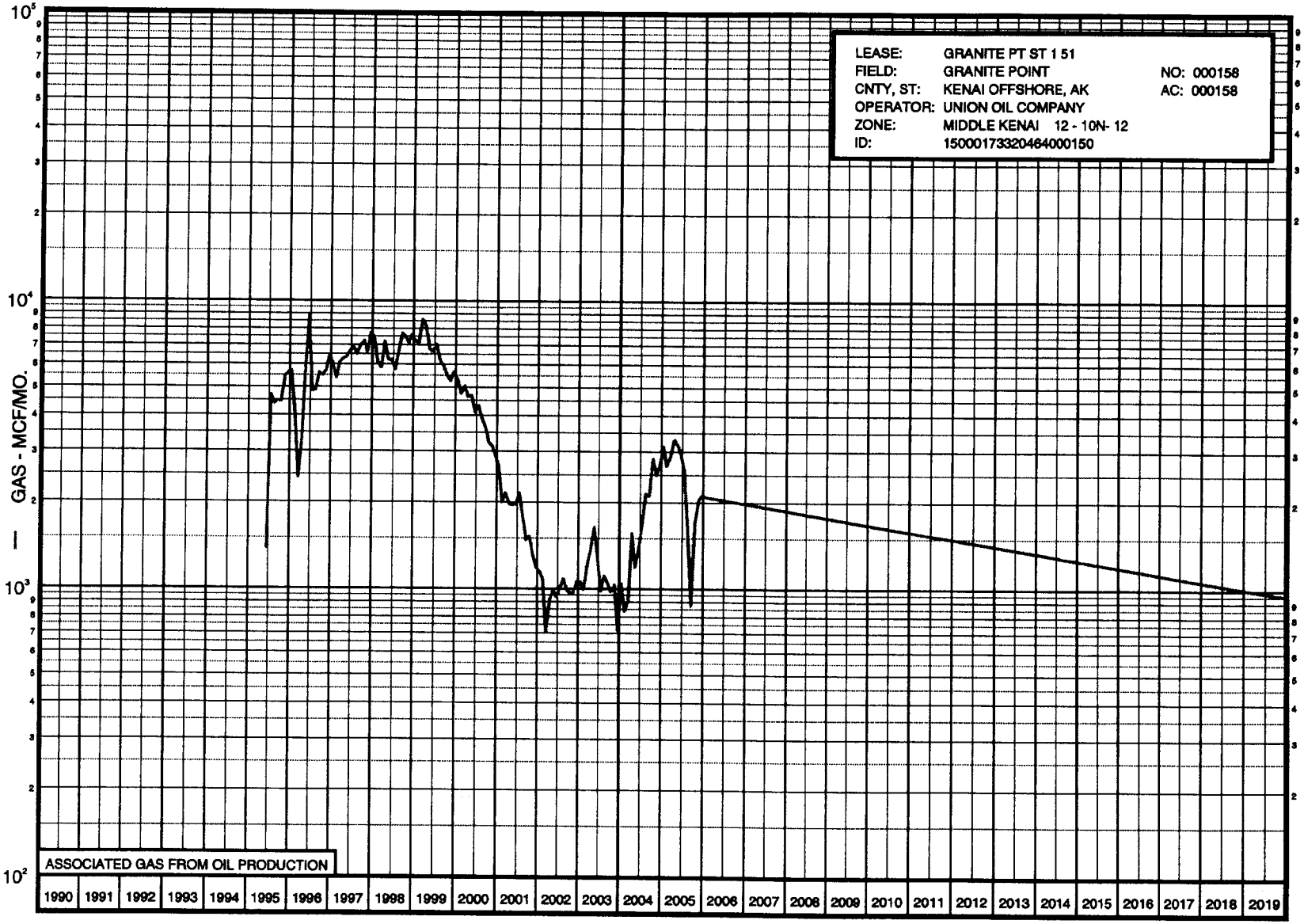

Figure 10.4.1.23

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NETHERLAND, SEWELL & ASSOCIATES, INC.

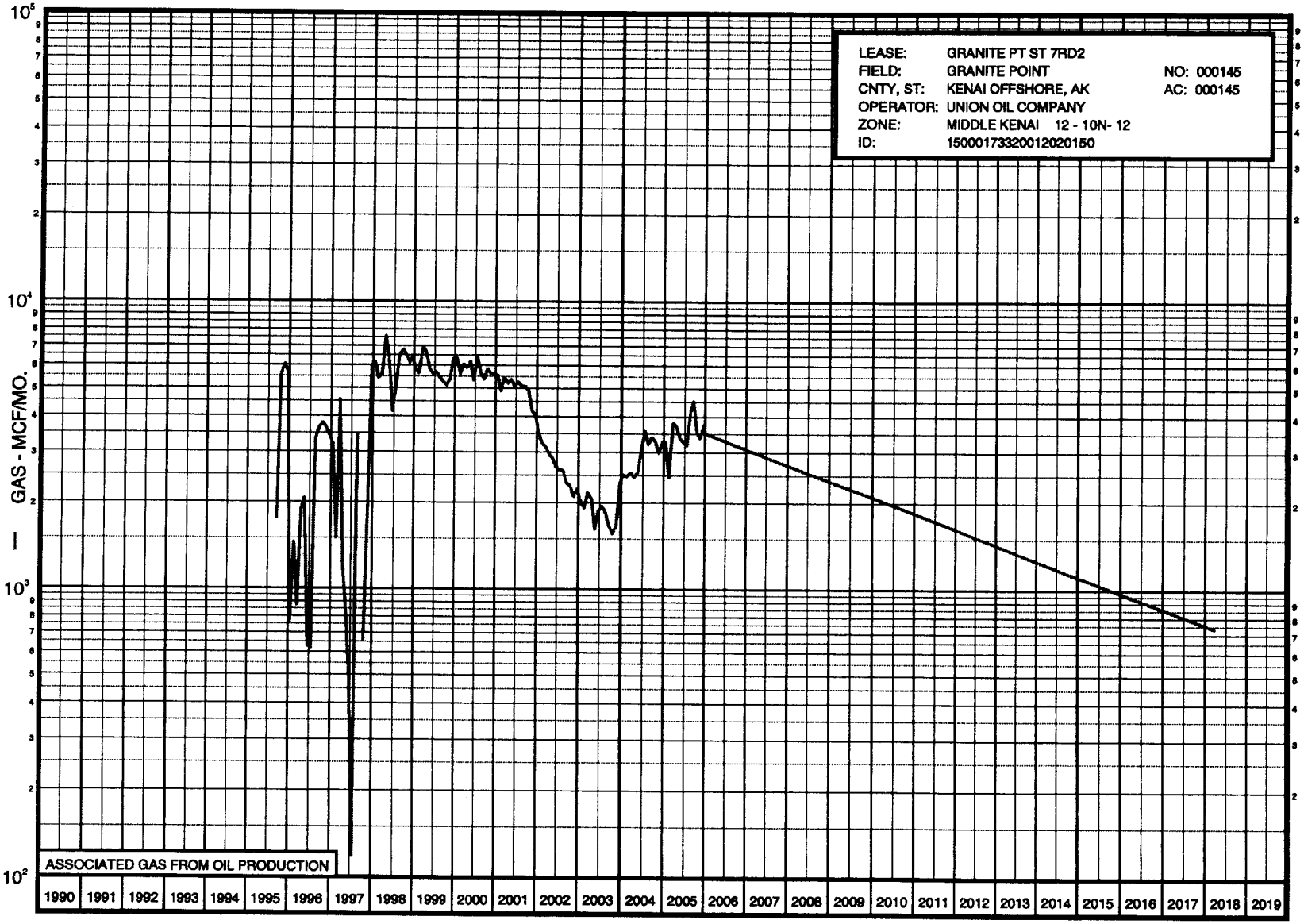

Figure 10.4.1.24

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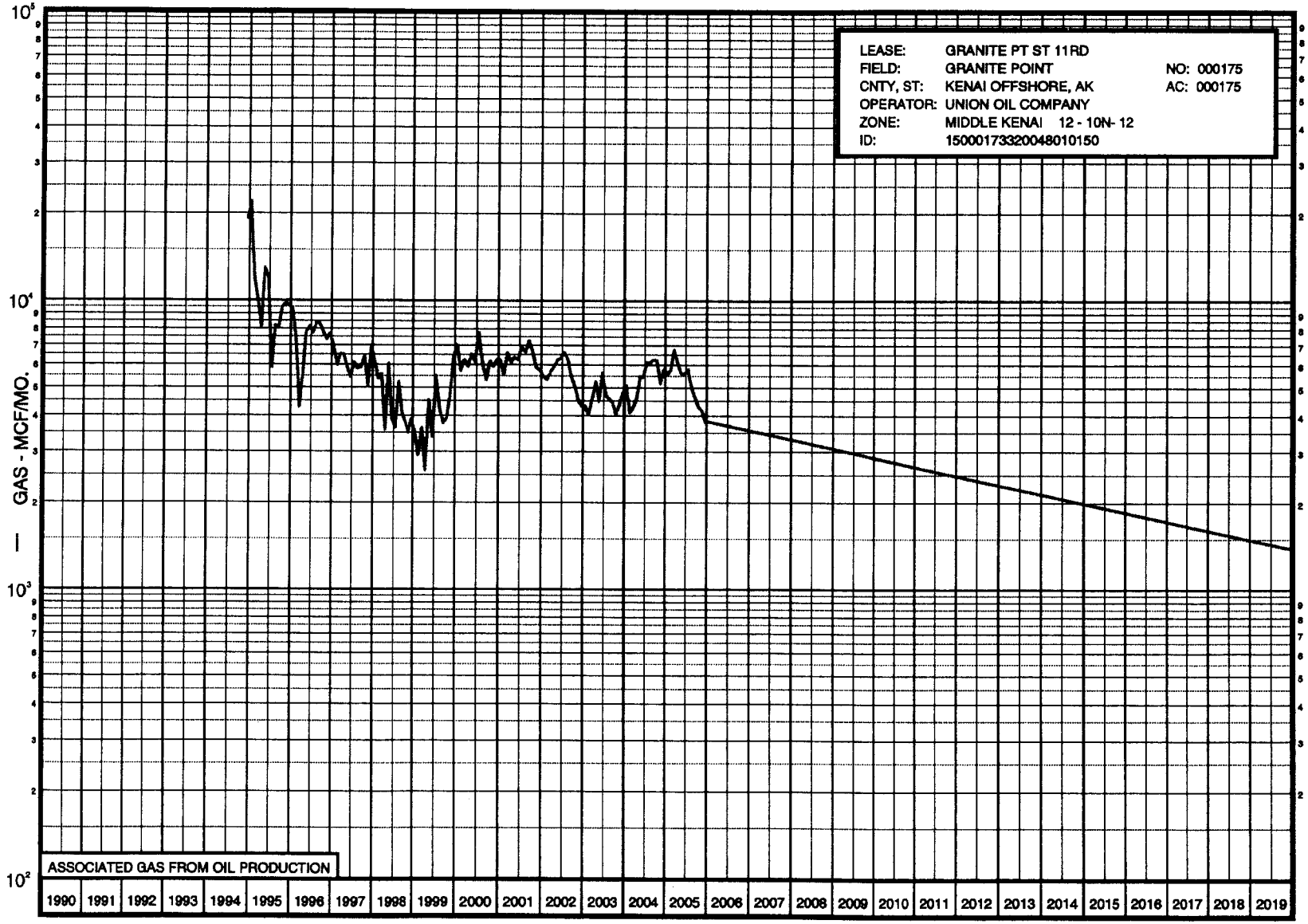
NETHERLAND, SEWELL & ASSOCIATES, INC.



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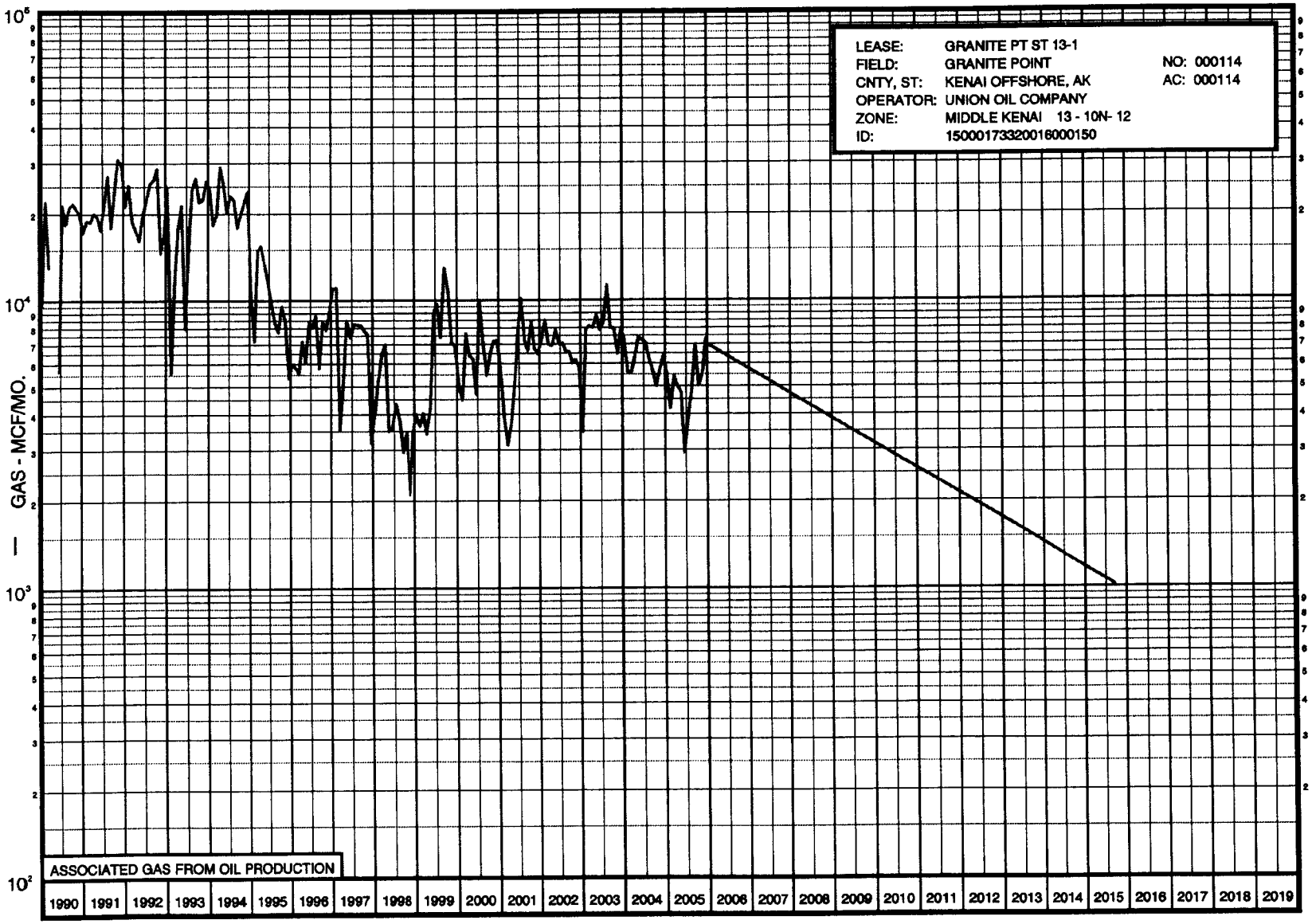

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