

**UNITED STATES OF AMERICA  
FEDERAL ENERGY REGULATORY COMMISSION**

**Southwest Gas Storage Company                      §                      Docket No. RP07-\_\_\_\_-000**

**PREPARED DIRECT TESTIMONY  
OF  
KAREN G. BENSON**

1    **Q. Please state your name and business address.**

2    A. My name is Karen G. Benson. My business address is 5444 Westheimer Road,  
3       Houston, Texas.

4    **Q. By whom are you employed and in what capacity?**

5    A. I am employed by Panhandle Eastern Pipe Line Company, LP ("Panhandle") as  
6       Director of Engineering Services in the Operations and Engineering Department. In  
7       addition to Panhandle, I have the same position with the other pipeline companies of  
8       the Panhandle Energy pipeline group which include Florida Gas Transmission  
9       Company, LLC ("Florida Gas"), Sea Robin Pipeline Company, LLC ("Sea Robin"),  
10       Southwest Gas Storage Company, ("Southwest Gas Storage"), Trunkline Gas  
11       Company, LLC ("Trunkline") and Trunkline LNG Company, LLC.

12       My present duties include directing the Operations and Engineering Audit group,  
13       Project Services group, and the Underground Storage group.

14   **Q. Please describe your pertinent employment history.**

15   A. I have been employed by Panhandle since 1979. From June 1979 until January 1983,  
16       I was employed as an Assistant Petroleum Engineer. During this period, I assisted in  
17       the development of the Borchers North Storage Field for Southwest Gas Storage and  
18       in the development of the Epps Storage Field for Trunkline. From January 1983

1       until October 1989, I was employed as a Petroleum Engineer and as a Division  
2       Petroleum Engineer. In this capacity, I provided underground gas storage  
3       engineering expertise for reservoirs, wells and surface equipment to the Panhandle  
4       Energy pipeline group. From October 1989 until February 1996, I was employed as  
5       a Senior Petroleum Engineer and as a Principal Petroleum Engineer. During this  
6       time, I assisted in the supervision of drilling a horizontal gas storage well and  
7       continued my responsibilities of providing underground gas storage engineering  
8       expertise for reservoirs, wells and surface equipment to Panhandle, Trunkline,  
9       Southwest Gas Storage, Centana Energy Corporation and Texas Eastern  
10       Transmission Corporation. From February 1996 until August 2000, I was employed  
11       as Manager of Underground Storage. In this capacity, I managed the activities of the  
12       Underground Storage group staff and provided underground gas storage engineering  
13       expertise for reservoirs, wells and surface equipment to the PanEnergy (later Duke  
14       Energy and CMS Energy) pipeline group. During this time, 5 horizontal wells were  
15       drilled and the Company developed two salt caverns for gas storage. From February  
16       2000 until December 2004, I was employed as Director of Facility Planning, Gas  
17       Storage and Reserves for the Panhandle Energy Pipeline group. In addition to my  
18       responsibilities of directing the gas storage group, I directed the facilities planning  
19       and gas reserves personnel. In December 2004, I assumed my present duties.

20       **Q. Please describe your educational background and any professional affiliations.**

21       A. I received my Bachelor of Science degree in Petroleum Engineering from The  
22       University of Tulsa in 1979. I am a member of the Society of Petroleum Engineers,  
23       and I served on the Underground Gas Storage Reprint panel responsible for the

1 selection of the twenty best papers written on underground natural gas storage for  
2 publication in the SPE Reprint series. I am a member of the Gas Research Institute /  
3 Pipeline Research Council, International Gas Storage Committee (for which I served  
4 as Vice Chairman from 2003-2005), the American Gas Association Operating  
5 Section Underground Storage Committee (for which I was chairman from 1994-  
6 1995) and of the Department of Energy Gas Storage Technical Consortium (for  
7 which I served on the Executive Council from 2003-2005).

8 **Q. Have you previously submitted testimony before the Federal Energy Regulatory**  
9 **Commission (Commission)?**

10 A. Yes. I have submitted testimony in Southwest Gas Storage Company, Docket No.  
11 RP07-34-000 and in Trunkline Gas Company, Docket No. RP96-129-000.

12 **Q. What is the scope of your testimony in this proceeding?**

13 A. My testimony provides a detailed explanation of the physical nature of Southwest  
14 Gas Storage's storage fields, and the reclassification of recoverable base gas to non-  
15 recoverable. My testimony supports aspects of the accompanying testimony of  
16 Southwest Gas Storage's witnesses Mr. Rickey J. Brocato and Mr. Michael T.  
17 Langston.

18 **Q. What Exhibits are you responsible for in this proceeding?**

1 A. I am responsible for the following exhibits and schedules which support my  
2 testimony and have been prepared by me or under my supervision:

3	<u>Exhibit No.</u>	<u>Reference</u>	<u>Description</u>
4	SGS-17		Reclassification of Base Gas
5	SGS-18		Waverly flowing pressure vs. time
6	SGS-19		Waverly withdrawal rate vs. time
7	SGS-20		Waverly withdrawal rate vs. inventory
8	SGS-21		Waverly economic limit calculation
9	SGS-22		N. Hopeton withdrawal rate and pressure vs.
10			inventory
11	SGS-23		N. Hopeton withdrawal rate vs. time
12	SGS-24		N. Hopeton economic limit calculation
13	SGS-25		Borchers North pressure vs. inventory
14	SGS-26		Borchers North withdrawal rate vs. time
15	SGS-27		Borchers North withdrawal rate and pressure
16			vs. inventory
17	SGS-28		Borchers North economic limit calculation
18	SGS-29		Howell pressure vs. inventory
19	SGS-30		Howell withdrawal rate vs. time
20	SGS-31		Howell withdrawal rate and pressure vs.
21			inventory
22	SGS-32		Howell economic limit calculation

23 **Q. What storage capacity does Southwest Gas Storage have available?**

24 A. Southwest Gas Storage owns four storage facilities: the Borchers North, Howell and  
25 North Hopeton Storage Fields which were converted from depleted natural gas  
26 producing fields to gas storage and the Waverly Storage Field which was an aquifer

1 (non-hydrocarbon bearing reservoir) converted to gas storage. In addition, Southwest  
2 Gas Storage has acquired third party storage from Tenaska Gas Storage, LLC  
3 ("TGS") pursuant to an executed contract dated April 4, 2007, as more fully  
4 explained in Mr. Langston's Exhibit No. SGS-1.

5 **Q. Please explain the characteristics of the facilities owned by Southwest Gas**  
6 **Storage.**

7 A. Borchers North Storage Field, located in Meade County, Kansas, is a volumetric, gas  
8 expansion drive reservoir with a base gas volume of 35.1 Bcf and maximum  
9 developed working storage capacity of 28.3 Bcf. The maximum withdrawal rate is  
10 350 MMcfd and the maximum injection rate is 300 MMcfd. There are 45  
11 injection/withdrawal wells and 10 observation wells. Installed compression consists  
12 of 5 identical units of 3,000 hp each for a total of 15,000 hp. The maximum wellhead  
13 surface injection pressure is 1,745 psig, and the minimum wellhead flowing pressure  
14 is 500 psig. The storage field gas feeds into Panhandle's main line in the Field zone,  
15 which averages around 700 psig of line pressure. The storage horizon at Borchers  
16 North is a sandstone reservoir of the Morrow series. The field is located near the  
17 northeastern edge of the Anadarko Basin. Sediments of the Pennsylvanian-aged  
18 Morrow were deposited in a shallow marine environment on an erosional surface of  
19 Mississippian-aged carbonates, filling topographically low areas. The reservoir is a  
20 stratigraphic trap formed by the pinch-out of the sand and by the degradation of  
21 effective permeability. The Morrow sand at Borchers North is generally divided into  
22 two areas on the basis of sand characteristics. The most productive portion of the  
23 reservoir is a narrow channel sand that cuts into the erosional surface on the  
24 Mississippian unconformity. The channel sand reaches a maximum thickness of 76

1 feet. The second portion of the sand overlays the thick channel sand. While this sand  
2 covers a larger area, it is shaly, fine-grained, somewhat lenticular and generally of  
3 lower quality. This part of the sand reaches a maximum thickness of 19 feet.

4 Although this sand is present down-dip in several dry holes in the area, it is water-  
5 bearing and of very low quality. The low permeability of the water-saturated sand  
6 may explain why very little water was produced during primary production or during  
7 storage operations. Reservoir communication exists between the two sand bodies,  
8 although the degree of communication depends on the specific area of the field and  
9 the amount of thin shale baffles present within the sand interval.

10 Howell Storage Field, located in Livingston County, Michigan is a volumetric, gas  
11 expansion drive reservoir with a base gas volume of 13.4 Bcf and maximum working  
12 gas volume of 17.8 Bcf. The maximum withdrawal rate is 410 MMcfd and maximum  
13 injection rate is about 140 MMcfd. There are 67 injection/withdrawal wells and 3  
14 observation wells. Installed compression consists of 2-1,000 hp units and 2-2,000 hp  
15 units for a total of 6,000 hp. The maximum wellhead surface injection pressure is  
16 1,892 psig, and the minimum wellhead flowing pressure is about 350 psig. The  
17 storage field gas feeds into Panhandle's main line in the Market zone, which averages  
18 around 600 psig of line pressure. The storage horizon at Howell is a dolomite  
19 reservoir in the Guelph formation of Niagaran age. The reservoir rock is a crystalline  
20 dolomite, with a "fairway" of high permeability developed throughout the vugular  
21 central portion of the field. The permeability decreases toward the outer edges,  
22 pinching out to a tight dolomitic matrix at the field boundaries. The porosity  
23 development is associated with a broad, symmetric southeast-northwest oriented  
24 anticline with a steeper dip on the southwest flank. The structure is approximately 5

1 miles long by 2 miles wide with about 200 feet of structural closure. The porosity  
2 development is in a 10-15 foot thick zone associated with reefing within the Niagaran  
3 formation near the southern rim of the Michigan Basin. The trap is stratigraphic with  
4 a structural component. The best rock quality is developed just off the crest of the  
5 structural high to the northeast and parallel to the anticlinal strike.

6 North Hopeton Storage Field, located in Woods County, Oklahoma, is a water drive  
7 gas reservoir currently certificated with 11.6 Bcf of base gas and maximum working  
8 storage capacity of 10.0 Bcf. Southwest proposed in Docket No. CP07-69-000,  
9 currently pending before the Commission, to increase the base gas to 14.6 Bcf and  
10 reduce the maximum working storage capacity to 3.5 Bcf to reflect actual field  
11 performance. The proposed design withdrawal rate is 35 MMcfd, with a maximum  
12 withdrawal rate of 100 MMcfd, and the proposed design injection rate is 17.5  
13 MMcfd. There are 14 injection/withdrawal wells, 4 observation wells and 2 salt  
14 water disposal wells. Installed compression consists of 3 units for a total of 5,600 hp.  
15 The maximum wellhead surface injection pressure is 3,000 psig, and the minimum  
16 wellhead flowing pressure is 500 psig. The storage field gas feeds into Panhandle's  
17 Elk City line in the Field zone, which averages around 600 psig of line pressure. The  
18 storage horizon at North Hopeton is a dolomitic formation in the Hunton Group of  
19 Silurian-Devonian age. The field lies on the northern shelf of the Anadarko Basin.  
20 The gas storage zone is a stratigraphic trap at the up-dip limit of the Hunton. This  
21 carbonate was deposited with a gradual thinning shelfward (to the north). A broad  
22 regional uplift to the north and a lowering of sea level during the Devonian time  
23 caused widespread erosion of the Hunton. The North Hopeton reservoir is located  
24 along this truncated edge of the Hunton in a narrow, northward-trending arm. To the

1 south of the field, the Hunton formation is an aquifer of large areal extent. This  
2 aquifer provides a partial water drive for the field. The Hunton dolomite interval can  
3 be subdivided into four layers on the basis of differing rock properties, although not  
4 all four layers are present in all wells. The total interval thickness ranges from 50 feet  
5 at the down-dip limits of the field to 32 feet in the up-dip wells. The lowermost layer  
6 generally has the best reservoir rock properties. The varying rock properties and the  
7 layered nature of the reservoir are partially responsible for the observation of uneven  
8 water encroachment as the pressure in the reservoir declines.

9 Waverly Storage Field, located in Morgan and Sangamon Counties, Illinois is an  
10 aquifer reservoir complex in three different reservoirs. The base gas volume is 46.6  
11 Bcf and maximum working gas volume is 5.0 Bcf. The maximum withdrawal rate is  
12 70 MMcfd and maximum injection rate is about 50 MMcfd. There are 37  
13 injection/withdrawal wells, 17 withdrawal only wells, 30 observation wells and 23  
14 facility wells. There are six compressor units totaling 5,550 horsepower. The  
15 maximum wellhead injection pressure is 845 psig with a minimum flowing pressure  
16 of about 75 psig. The storage field gas feeds into Panhandle's 100 line in the Market  
17 zone, which averages around 425 psig of line pressure. Waverly Field is in the north-  
18 central portion of the Illinois Basin. The storage zones at Waverly were all originally  
19 water-bearing formations. The domal structure at Waverly has a closure of about 100  
20 feet, and covers an area of about 9,100 acres. The principal storage horizon at  
21 Waverly is the St. Peter sandstone of Ordovician age. It is a highly permeable,  
22 friable, fine-to-medium grained quartz sandstone, and it averages about 200 feet  
23 thick. The first Collection zone above the St. Peter formation is the Joachim "B"  
24 formation, also of Ordovician age. It is a finely crystalline dolomite with vuggy-to-



1 intergranular porosity and some thin shale layers. It averages about 56 feet thick.  
2 The second Collection zone is the Decorah "A" formation, also of Ordovician age. It  
3 too is a porous dolomite with similar characteristics to the Joachim, and it averages  
4 about 12 feet thick. The Collection zones operate as withdrawal-only reservoirs and  
5 contain gas that has migrated upward from the St. Peter formation.

6 **Q. How do the reservoir characteristics relate to the management of the storage**  
7 **fields?**

8 A. When the reservoir's areal extent, net thickness, porosity (a measure of the percentage  
9 of void space within the rock), water saturation (a measure of the percentage of the  
10 void space filled with water), reservoir pressure and temperature are known, then the  
11 reservoir's capacity to hold gas can be determined. These factors determine the  
12 storage field's total capacity. The reservoir rock's permeability (a measure of the  
13 ability of fluids to flow through the rock) is ultimately related to the storage field's  
14 deliverability and injectivity. These reservoir characteristics impact the storage field  
15 design, including number of wells needed and the amount of horsepower required to  
16 provide the desired level of service. The reservoir drive mechanism (gas expansion  
17 drive at the Borchers North and Howell storage fields and water drive at the North  
18 Hopeton and Waverly storage fields) impacts the amount of base gas required to  
19 provide the desired level of working storage capacity, and also the amount of base gas  
20 that can ultimately be recovered upon abandonment of the storage facility.

21 **Q. How does a water drive gas field differ from a volumetric, expansion drive gas**  
22 **field?**

23 A. There are several differences between a water drive gas field and a volumetric,  
24 expansion drive gas field. In a gas expansion drive reservoir, the reservoir's energy

1 comes from the expansion of the gas as it flows from an area of higher pressure to an  
2 area of lower pressure. Since the well flow is single phase gas, the facilities are less  
3 complicated and easier to operate. In addition, variation in the individual well flow  
4 rates is not as critical since water influx and efflux are not issues in gas expansion  
5 reservoirs. In a water drive reservoir, the reservoir's energy comes all or in part from  
6 the expansion of water in contact with the reservoir gas and the water-bearing sand,  
7 or aquifer. The effect of water movement in the reservoir is multifold. As gas is  
8 removed and water moves in, wells completed below the gas/water contact will water  
9 out and deliverability will decline more quickly than in expansion drive reservoirs. In  
10 reservoirs that are not homogeneous, water encroachment can follow the "path of  
11 least resistance" and preferentially invade high permeability areas of the reservoir.  
12 Gas flow from these areas is effectively blocked, and the stranded gas essentially  
13 behaves like base gas. In addition to these detrimental effects on deliverability and  
14 capacity, water production increases both the capital and operating costs of storage.  
15 Additional equipment needed to handle water production can include well equipment  
16 (tubing, submersible pumps, gas lift valves, etc.), salt water holding tanks, salt water  
17 flow lines, salt water disposal wells, water injection pumps, separation and filtration  
18 equipment and dehydration equipment. Increased operating costs that result from  
19 water production can include salt water trucking, chemicals used to prevent corrosion,  
20 service interruptions to clear freezes and/or run periodic line cleaners, chemicals used  
21 for dehydration, costs to maintain salt water disposal wells' productivity and  
22 increased labor to maintain the additional equipment. Salt water spills can also  
23 increase environmental mitigation costs.

24 **Q. How is the working storage capacity determined?**

1 A. Before working gas capacity can be determined, the total storage capacity, which  
2 includes both base and working gas, must be determined from volumetric and/or field  
3 performance data. Once the total capacity is known, then working gas becomes a  
4 design parameter based on minimum flowing pressure and delivery requirements. It  
5 is an optimization exercise with the amount and unit cost of base gas, amount of  
6 compression and number of wells as input parameters.

7 **Q. What is the function of base gas?**

8 A. The function of base gas is to provide the required reservoir energy (pressure) to  
9 allow for withdrawal of all the working gas within the desired time frame at the rates  
10 required to meet contractual obligations.

11 **Q. How is the level of base gas determined to achieve the working storage**  
12 **capability?**

13 A. The level of base gas required is a function of the minimum flowing pressure the  
14 storage facility can achieve. In some cases, the field compression was designed to  
15 provide injection service only and the minimum flowing pressure becomes the  
16 pipeline pressure. In other cases, the field compression was designed to provide both  
17 injection and withdrawal service, and in those cases the minimum flowing pressure is  
18 normally lower than the pipeline pressure. The base gas is the amount of gas required  
19 to fill the reservoir up to the minimum flowing pressure.

20 **Q. Please explain the classification of base gas into recoverable and non-**  
21 **recoverable.**

22 A. All base gas is utilized to maintain adequate pressure within the storage reservoir.  
23 However, it can be classified as either recoverable or non-recoverable. Recoverable  
24 base gas is that amount of the base gas that could be economically produced after the

1 reservoir was no longer required for storage service. Non-recoverable base gas is the  
2 amount of base gas that remains in the reservoir after the recoverable base gas is  
3 removed. The gas remains in the storage reservoir because the cost to produce this  
4 gas is greater than its economic value.

5 **Q. What characteristics of the storage facilities are evaluated to determine that**  
6 **certain base gas volumes should be classified as either recoverable or non-**  
7 **recoverable?**

8 A. The storage reservoir performance must be evaluated in order to estimate the flow  
9 rates the facility can achieve over time after all the working gas is removed. This  
10 estimate provides the amount of base gas volume that could be produced once the  
11 reservoir is taken out of storage service. The expenses to operate the facility over this  
12 same time period are also estimated. The price of gas is estimated and multiplied by  
13 the gas produced to determine the value of the recovered base gas. When the  
14 expenses exceed the value, the economic limit to production is reached, and the base  
15 gas remaining is considered non-recoverable.

16 **Q. How did Southwest Gas Storage determine the level of base gas to be reclassified**  
17 **from recoverable to non-recoverable?**

18 A. The non-recoverable base gas for each storage field was evaluated on an individual  
19 basis. Final abandonment conditions were determined for each field. All working  
20 gas was considered removed, leaving only base gas. Monthly base gas production  
21 and expenses for the recovery of the base gas were estimated. The price of gas used  
22 in the evaluation was \$7.94 per Mcf, which was the 12-month NYMEX strip price for  
23 July 2007 through June 2008, as of July 3, 2007 (when the analysis was undertaken).  
24 The economic production limit was determined by field, and the base gas remaining

1 after that point in time was considered to be non-recoverable base gas.

2 **Q. What volume of base gas does Southwest Gas Storage need to reclassify from**  
3 **recoverable to non-recoverable?**

4 A. My evaluation shows that 26,617,738 Mcf of base gas should be reclassified from  
5 recoverable to non-recoverable. My Exhibit No. SGS-17 details this volume by  
6 storage field.

7 **Q. How was the non-recoverable base gas calculated for Waverly?**

8 A. The Waverly Storage Field is a complex aquifer storage system operated in three  
9 different zones. Exhibit No. SGS-18 shows wellhead flowing pressure versus days on  
10 withdrawal for the last five withdrawal seasons (2002-2003, 2003-2004, 2004-2005,  
11 2005-2006 and 2006-2007). The wellhead flowing pressure approaches the minimum  
12 line pressure of 75 psig each withdrawal season. Exhibit No. SGS-19 shows  
13 withdrawal rate versus days on withdrawal for the same 5 withdrawal seasons. The  
14 withdrawal rate approaches 2 MMcfd near the end of each withdrawal season. Only a  
15 few wells (less than 10 out of 54) are left producing from the highest parts of each  
16 structure. All the other wells successively water out as the withdrawal season  
17 progresses. Exhibit No. SGS-20 shows the withdrawal rate versus total inventory for  
18 these same 5 withdrawal seasons. This exhibit shows that the withdrawal rate is  
19 reduced to 2-4 MMcfd as the inventory approaches 46.6 Bcf, which is the base gas  
20 level. These three exhibits graphically depict the withdrawal capability of the three  
21 reservoirs at Waverly. By the end of the withdrawal season, the facility reaches  
22 minimum flow rates and pressures, and essentially all the gas that can be withdrawn  
23 has been produced. Exhibit No. SGS-21 shows the calculation of the economic limit  
24 to base gas production for the Waverly Storage Field. For this analysis, all of the

1 working gas is assumed to have already been withdrawn. At time = 0 months, the  
2 field is assumed to start producing base gas. The first column in the schedule  
3 (entitled "Mo") is the month since base gas production commenced. The next column  
4 (entitled "Base Gas Production Avg. Rate (Mcf/D)") is the average rate at which the  
5 field produced base gas for that month. The next column (entitled "Base Gas  
6 Production Monthly (Mcf)") is the volume of base gas produced for that month. The  
7 next column (entitled "Cum Production (Mcf)") is the cumulative volume of base gas  
8 produced through that month. The next column (entitled "Gas Price (\$/Mcf)") is the  
9 assumed unit price of gas, as described earlier in this testimony. The next column  
10 (entitled "Gross Economic Value (\$)") is the gross value associated with that month's  
11 base gas production, calculated by multiplying the unit price of gas by the monthly  
12 base gas production. The next column (entitled "Operating Expenses (\$)") is the  
13 assumed monthly cost to operate the facilities for base gas production. The next  
14 column (entitled "Fuel Costs (\$)") is the assumed cost of the compressor fuel used to  
15 produce the base gas for that month (if compression is required). The next column  
16 (entitled "Amortization of Capital (\$)") is 1/12 of the capital expenditures (if  
17 required) to continue base gas production for that month. The next column (entitled  
18 "Net Economic Value (\$)") is the Gross Economic Value minus the Operating  
19 Expenses, Fuel Costs and Amortized Capital Expense for that month. The last  
20 column (entitled "Remaining Base Gas (Mcf)") is the volume of base gas left in the  
21 storage field as of that month. The economic limit to base gas production occurs  
22 when the expenses associated with base gas production exceed the value for the base  
23 gas produced that month. This calculation utilizes the current market value for the  
24 projected gas produced, as compared to the operating expenses necessary to generate

1 the gas production. The calculations indicate that base gas can be recovered from the  
2 Waverly Storage Field over a production period of 3 months. The recoverable base  
3 gas is determined to be 300,081 Mcf, leaving 15,769,791 Mcf to be re-classified as  
4 non-recoverable base gas.

5 **Q. How was the non-recoverable base gas calculated for North Hopeton?**

6 A. The geological and storage performance data from North Hopeton indicate that  
7 water from the high permeability layers impedes the gas flow into the wellbores. The  
8 reservoir remains at relatively high pressure even at the end of the withdrawal season,  
9 when the withdrawal rate has been reduced to very low levels. The deliverability  
10 model used to calculate the withdrawal rates expected during base gas recovery  
11 combines the traditional gas well back pressure relationship with the gas material  
12 balance equation. The flow performance coefficient, c, and exponent, n in the gas  
13 well deliverability relationship:

14 
$$q = c(p_s^2 - p_w^2)^n$$

15 are based on an average well computation. The other terms in this equation are q =  
16 flow rate,  $p_s$  = reservoir shut-in pressure and  $p_w$  = reservoir flowing pressure. The  
17 model allows multiple wells to be used in predicting performance. Due to the  
18 variable reservoir rock properties present in the Hunton formation at North Hopeton,  
19 gas depletion is not uniform. Water encroaches through the storage wellbores and  
20 blocks gas flow from various areas in the reservoir. Once the field withdrawal rate  
21 drops below 5 MMcfd during the base gas recovery period, five of the wells located  
22 in the highest part of the structure will be recompleted to reduce the amount of water  
23 entering the wellbores. The existing perforations will be plugged off and the wells  
24 will be reperforated at the top of the Hunton zone at a cost of \$120,000 per well

1 (\$600,000 total). These capital costs are accounted for in the determination of the  
2 economic limit. The gas material balance equation relates reservoir pressure (BHP)  
3 to cumulative withdrawal and maximum inventory as follows:

$$4 \quad \text{BHP}/Z = (\text{BHP}/Z)_i(1 - \text{cumulative withdrawal}/\text{maximum inventory})$$

5 where Z is the gas compressibility factor at BHP. Predictions of flow rates during the  
6 base gas recovery period are made by specifying the time step, initial flow rate,  
7 flowing and shut-in reservoir pressures, and calculating the flow rate at the next time  
8 step. Exhibit No. SGS-22 is a graphical depiction of the solution of the deliverability  
9 model for North Hopeton. It shows predicted withdrawal rate and reservoir pressure  
10 versus remaining inventory. Exhibit No. SGS-23 shows the predicted withdrawal rate  
11 versus time for the base gas recovery period. Exhibit No. SGS-24 shows the  
12 calculation of the economic limit to base gas production for the North Hopeton  
13 Storage Field. The structure of this schedule is the same as the schedule presented  
14 earlier in this testimony for the Waverly Storage Field in Exhibit No. SGS-21. Since  
15 the calculations were explained extensively in the description of the Waverly exhibit,  
16 they will not be repeated here. The calculations indicate that base gas can be  
17 recovered from the North Hopeton Storage Field over a production period of 34  
18 months. The recoverable base gas is determined to be 3,909,000 Mcf, leaving  
19 3,591,057 Mcf to be re-classified as non-recoverable base gas. These calculations are  
20 based on the originally certificated base gas volume of 11.6 Bcf. Southwest Gas  
21 Storage has filed to acquire an additional 3 Bcf of base gas for the North Hopeton  
22 Storage Field, as detailed in Southwest Gas Storage's Docket No. CP07-69-000. This  
23 3 Bcf of additional base gas will be recoverable. Upon receipt of the certificate in  
24 that proceeding, the total base gas at North Hopeton will be revised to 14.6 Bcf, of



1 which 6,909,000 Mcf will be recoverable, and 7,691,000 Mcf will be non-  
2 recoverable.

3 **Q. How was the non-recoverable base gas calculated for Borchers North?**

4 A. The pre-storage production history at Borchers North was modeled with a three  
5 dimensional, three phase reservoir simulation. The reservoir structure, isopach and  
6 porosity maps were digitized, and an areal grid system was superimposed over the  
7 digitized data. The analysis was initialized with 70.1 Bcf of gas-in-place, and each  
8 production well was assigned its historical flow rates during the pre-storage, primary  
9 production period from 1960 to 1980. Individual well measured pressures were  
10 compared to the calculated well pressures. The simulation predicted pressures that  
11 generally agreed with the historical measured pressures. The simulation was thus  
12 considered calibrated, and it should provide an accurate prediction of reservoir  
13 behavior during base gas recovery. The reservoir simulation was re-initialized with  
14 inventory of 35.1 Bcf (base gas only). For the base gas recovery simulation, all 45  
15 injection/withdrawal wells were placed on withdrawal. For the first six months of the  
16 simulation, the wells produced against the existing compressor suction pressure of  
17 350 psig. When the field rate declined below 30 MMcfd, a skid-mounted rental  
18 compressor was projected to be installed, and the wells produced against a suction  
19 pressure of 150 psig. Exhibit No. SGS-25 depicts BHP/Z versus inventory for the  
20 storage period (actual data) and the base gas recovery period (calculated by the  
21 simulation). The continuity between the historical storage data and the calibrated  
22 reservoir model confirms the expected accuracy of the prediction of the reservoir's  
23 behavior during base gas recovery. Exhibit No. SGS-26 shows the predicted  
24 withdrawal rate versus time for the base gas recovery period. The abrupt slope

1 change after 6 months of production results from replacing the existing compression  
2 with the rental compression. Exhibit No. SGS-27 depicts predicted withdrawal rate  
3 and reservoir pressure versus remaining inventory during the base gas recovery  
4 simulation. Exhibit No. SGS-28 shows the calculation of the economic limit to base  
5 gas production for the Borchers North Storage Field. The structure of this schedule is  
6 the same as the schedule presented earlier in this testimony for the Waverly Storage  
7 Field in Exhibit No. SGS-21. The calculations indicate that the base gas can be  
8 recovered from the Borchers North Storage Field over a production period of 33  
9 months. The recoverable base gas is determined to be 23,952,226 Mcf, leaving  
10 7,461,955 Mcf to be re-classified as non-recoverable base.

11 **Q. How was the non-recoverable base gas calculated for Howell?**

12 A. The storage history of the Howell Storage Field was modeled using a three  
13 dimensional, two phase reservoir simulation. The reservoir structure, isopach and  
14 porosity maps were digitized, and an areal grid system was superimposed over the  
15 digitized data. The simulation was initialized from full inventory with reservoir  
16 pressure of 2,074 psig, and utilized two and a half years of storage history. Actual  
17 injection and withdrawal volumes by well were input into the analysis. Individual  
18 well measured pressures were compared to the calculated well pressures. The  
19 simulation predicted pressures that generally agreed with the historical measured  
20 pressures. The simulation was thus considered calibrated, and should provide an  
21 accurate prediction of reservoir behavior during base gas recovery. The base gas  
22 recovery simulation was again initialized at full inventory and placed on withdrawal  
23 for 127 days until only base gas remained. For the base gas recovery period, all 67  
24 storage wells were placed on withdrawal. For the initial part of the simulation, the

1 wells produced against the existing compressor suction pressure of 350 psig. When  
2 the field rate declined below 15 MMcfd, a skid-mounted rental compressor was  
3 projected to be installed, and the wells produced against a suction pressure of 150  
4 psig. Exhibit No. SGS-29 depicts BHP/Z versus inventory for the storage period  
5 (actual data) and the base gas recovery period (calculated by the simulation). The  
6 continuity between the historical storage data and the calibrated reservoir simulation  
7 confirms the expected accuracy of the prediction of the reservoir's behavior during  
8 base gas recovery. Exhibit No. SGS-30 shows predicted withdrawal rate versus time  
9 for the base gas recovery period. The abrupt slope change after 6 months of  
10 production results from replacing the existing compression with the rental  
11 compression. Exhibit No. SGS-31 depicts predicted withdrawal rate and reservoir  
12 pressure versus remaining inventory during the base gas recovery simulation. Exhibit  
13 No. SGS-32 shows the calculation of the economic limit to base gas production for  
14 the Howell Storage Field. The structure of this schedule is the same as the schedule  
15 presented earlier in this testimony for the Waverly Storage Field in Exhibit No. SGS-  
16 21. The calculations indicate that the base gas can be recovered from the Howell  
17 Storage Field over a production period of 43 months. The recoverable base gas is  
18 determined to be 8,519,224 Mcf, requiring 205,065 Mcf to be re-classified from non-  
19 recoverable to recoverable base.

20 **Q. With the updated economic calculations for all four fields which you have**  
21 **explained, what are the total changes for Southwest Gas Storage in recoverable**  
22 **to non-recoverable base gas volumes?**

23 A. Southwest Gas Storage currently has recoverable base gas volumes of 63,298,269  
24 Mcf, and non-recoverable base gas volumes of 43,417,262 Mcf. The calculations,

1 included in my exhibits and as explained above, indicate that the proper classification  
2 is 36,680,531 Mcf for recoverable base gas volumes and 70,035,000 Mcf for non-  
3 recoverable base gas volumes.

4 **Q. Does the reclassification of base gas affect the operation of the storage fields?**

5 A. No. The operation of the storage fields is not affected by the reclassification of base  
6 gas. The total amount of base gas does not change. Each storage field has the same  
7 working storage capacity as I have previously described.

8 **Q. Does this conclude your direct testimony?**

9 A. Yes it does.

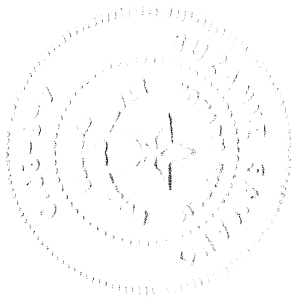
The State of Texas }  
                              } SS.  
County of Harris }

BEFORE ME, the undersigned authority, on this day personally appeared  
Karen G. Benson, who being by me first duly sworn, on oath deposes and says:

That she is the Karen G. Benson, offering the foregoing prepared direct testimony  
and that all statements of fact contained therein are true and correct to the best of her  
knowledge, information and belief.

  
\_\_\_\_\_  
Karen G. Benson

Subscribed and sworn to before me this 27<sup>th</sup> day of July, 2007.



  
\_\_\_\_\_  
Notary Public

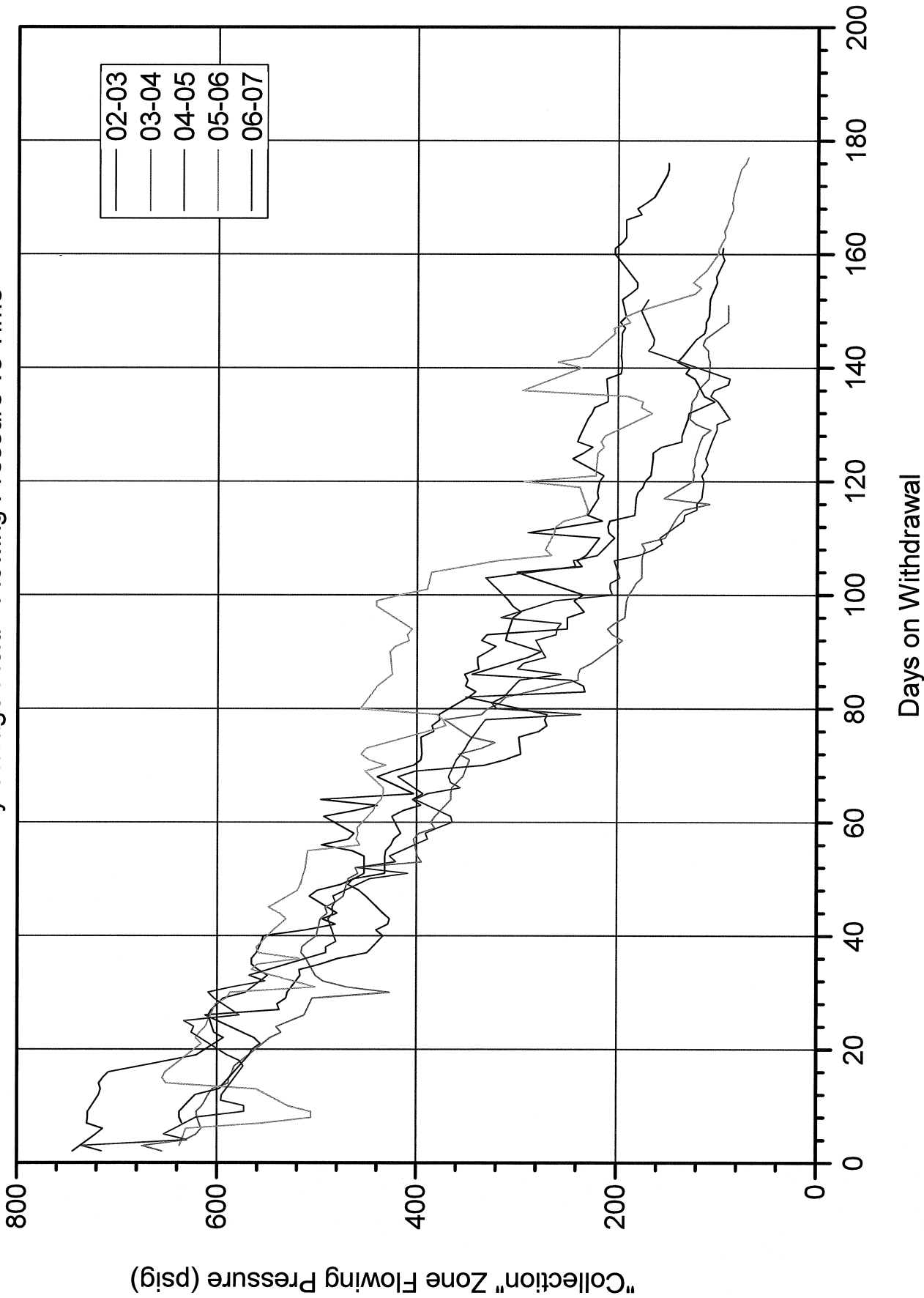
My Commission Expires:

April 6, 2010

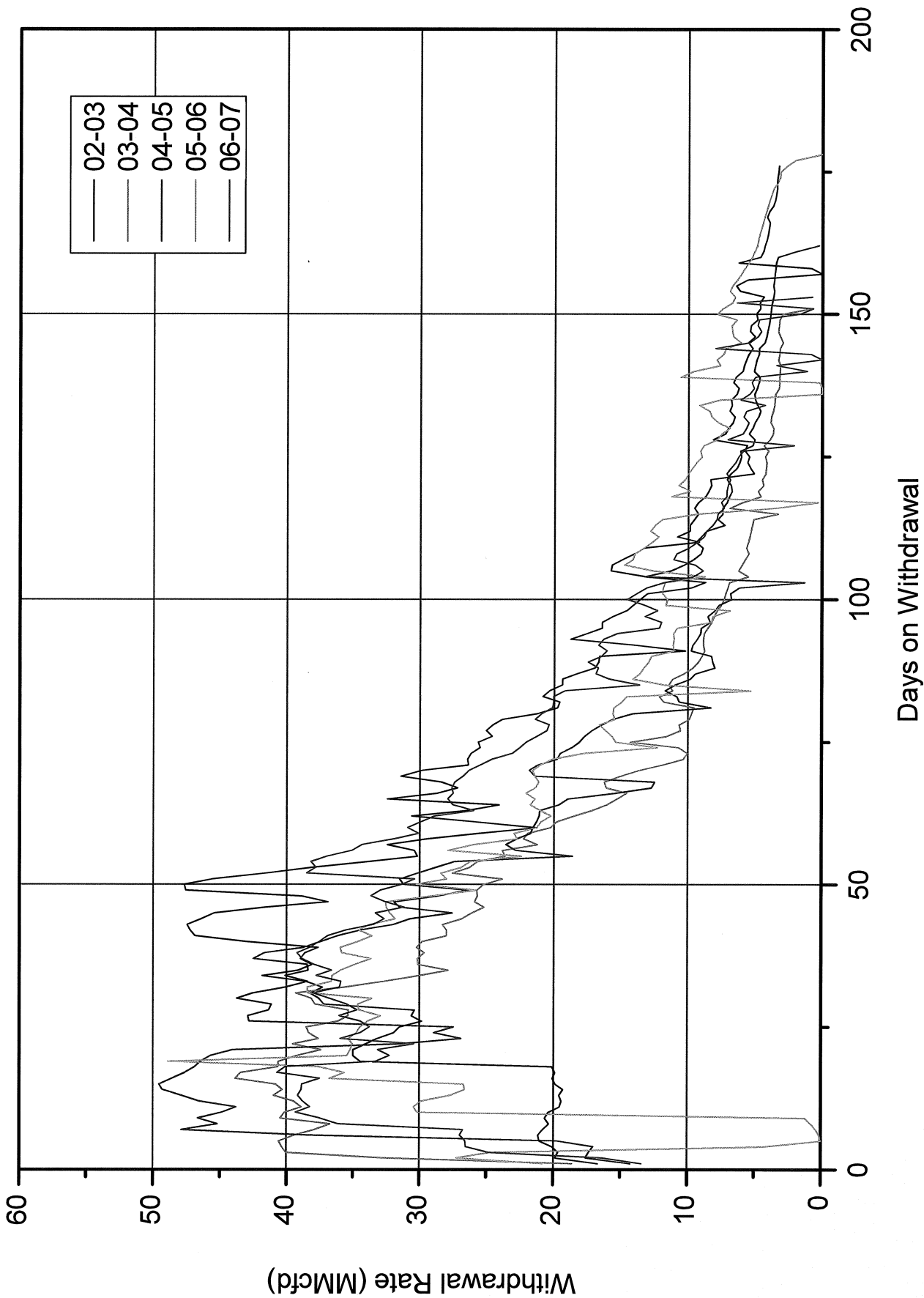
SOUTHWEST GAS STORAGE COMPANY  
Reclassification of Base Gas

Line No.	Storage Field	Current Base Gas, Mcf (a)	Redetermined Base Gas, Mcf (b)	Reclassification Adjustment (c)
<u>West Area</u>				
Borchers North				
1	- Recoverable	31,414,181	23,952,226	(7,461,955)
2	- Non-Recoverable	3,667,045	11,129,000	7,461,955
3	Total Base Gas	35,081,226	35,081,226	-
North Hopeton				
4	- Recoverable	7,500,057	3,909,000	(3,591,057)
5	- Non-Recoverable	4,099,943	7,691,000	3,591,057
6	Total Base Gas	11,600,000	11,600,000	-
Total West Area				
7	- Recoverable	38,914,238	27,861,226	(11,053,012)
8	- Non-Recoverable	7,766,988	18,820,000	11,053,012
9	Total Base Gas	46,681,226	46,681,226	-
<u>East Area</u>				
Waverly				
10	- Recoverable	16,069,872	300,081	(15,769,791)
11	- Non-Recoverable	30,550,209	46,320,000	15,769,791
12	Total Base Gas	46,620,081	46,620,081	-
Howell				
13	- Recoverable	8,314,159	8,519,224	205,065
14	- Non-Recoverable	5,100,065	4,895,000	(205,065)
15	Total Base Gas	13,414,224	13,414,224	-
Total East Area				
16	- Recoverable	24,384,031	8,819,305	(15,564,726)
17	- Non-Recoverable	35,650,274	51,215,000	15,564,726
18	Total Base Gas	60,034,305	60,034,305	-
<u>Total</u>				
19	- Recoverable	63,298,269	36,680,531	(26,617,738)
20	- Non-Recoverable	43,417,262	70,035,000	26,617,738
21	Total Base Gas	106,715,531	106,715,531	-

SOUTHWEST GAS STORAGE COMPANY  
Waverly Storage Field - Flowing Pressure vs Time

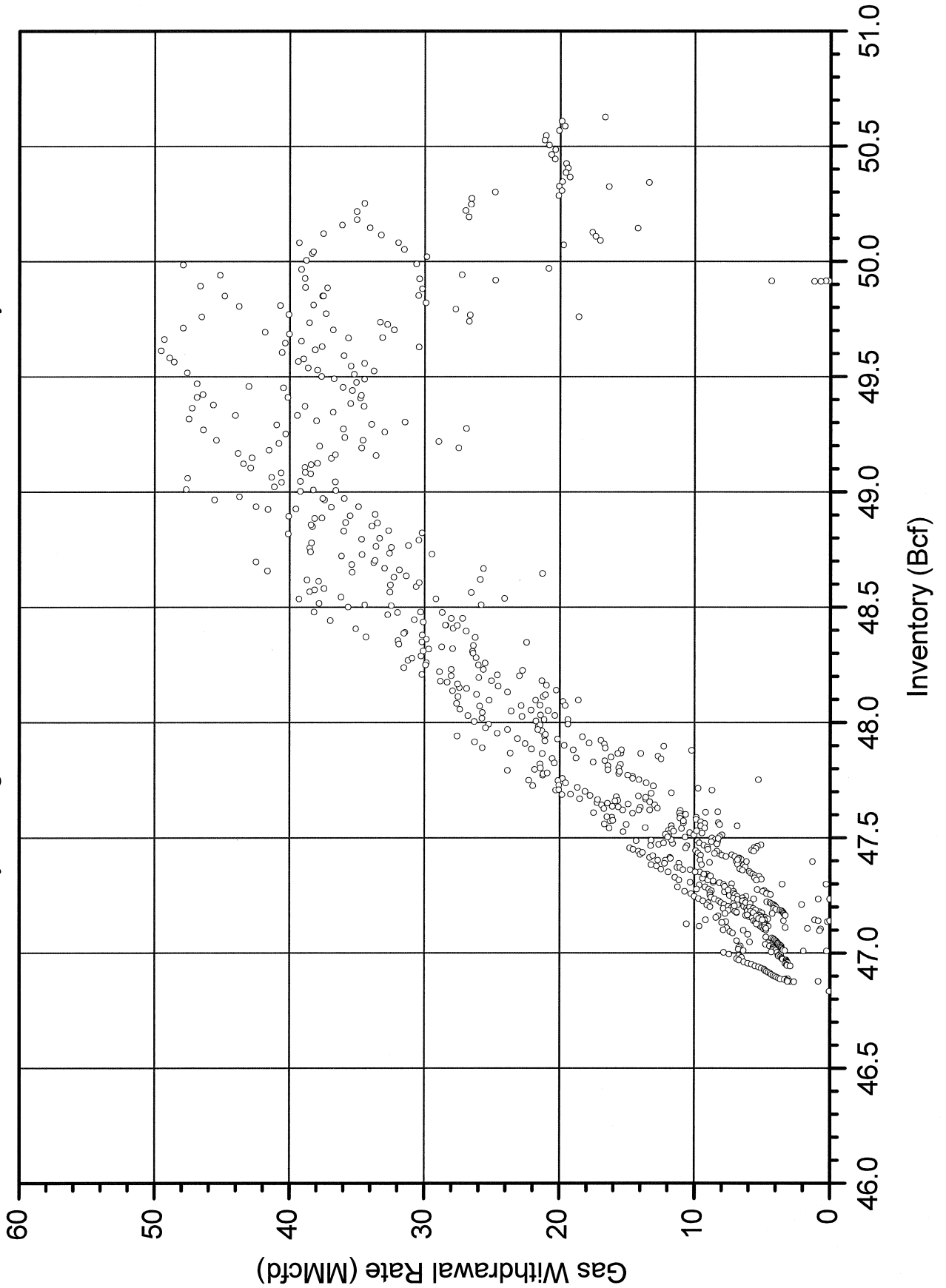


SOUTHWEST GAS STORAGE COMPANY  
Waverly Storage Field - Withdrawal Rate vs. Time





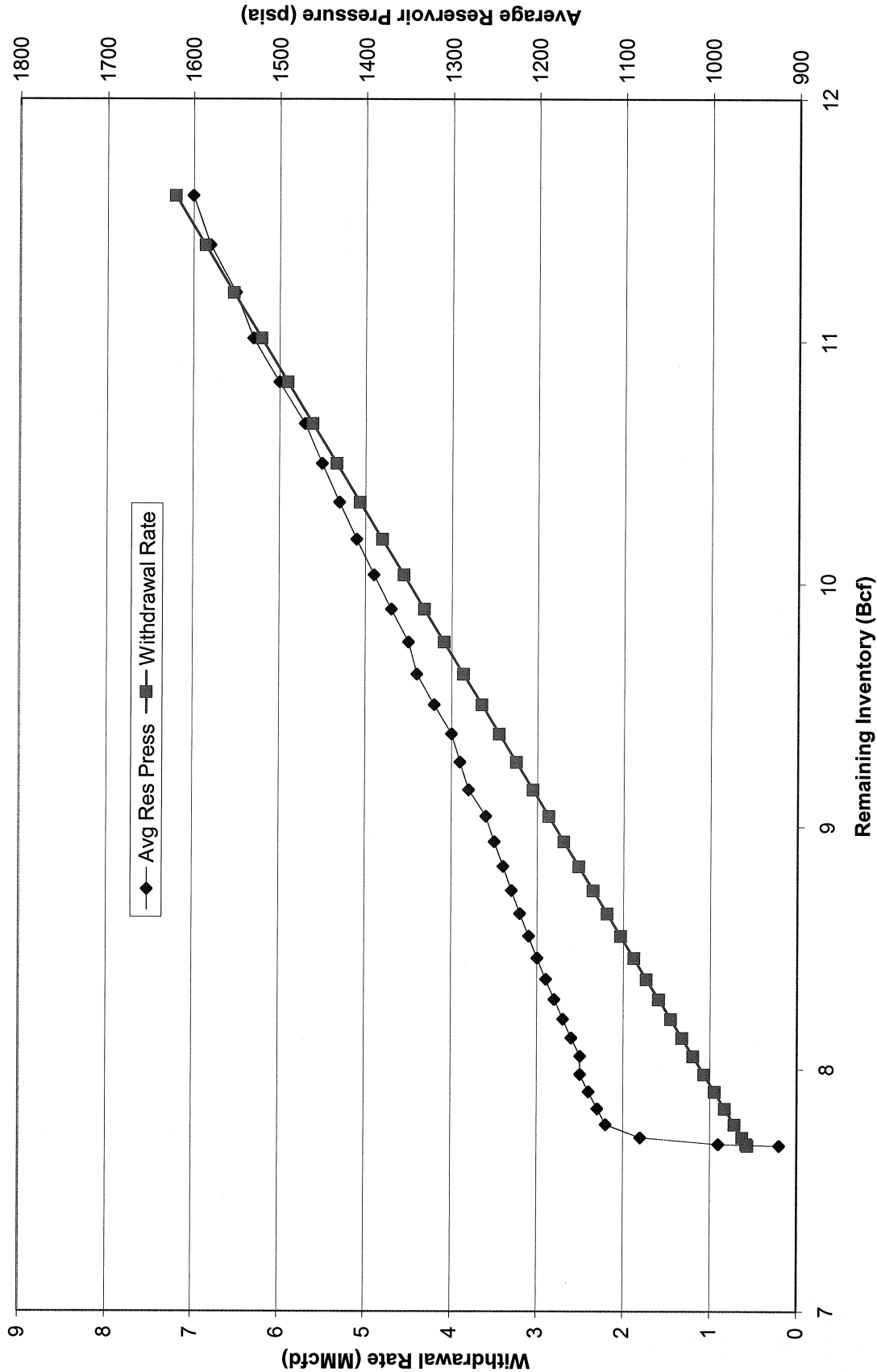
SOUTHWEST GAS STORAGE COMPANY  
Waverly Storage Field - Withdrawal Rate vs Inventory, 2002-2007



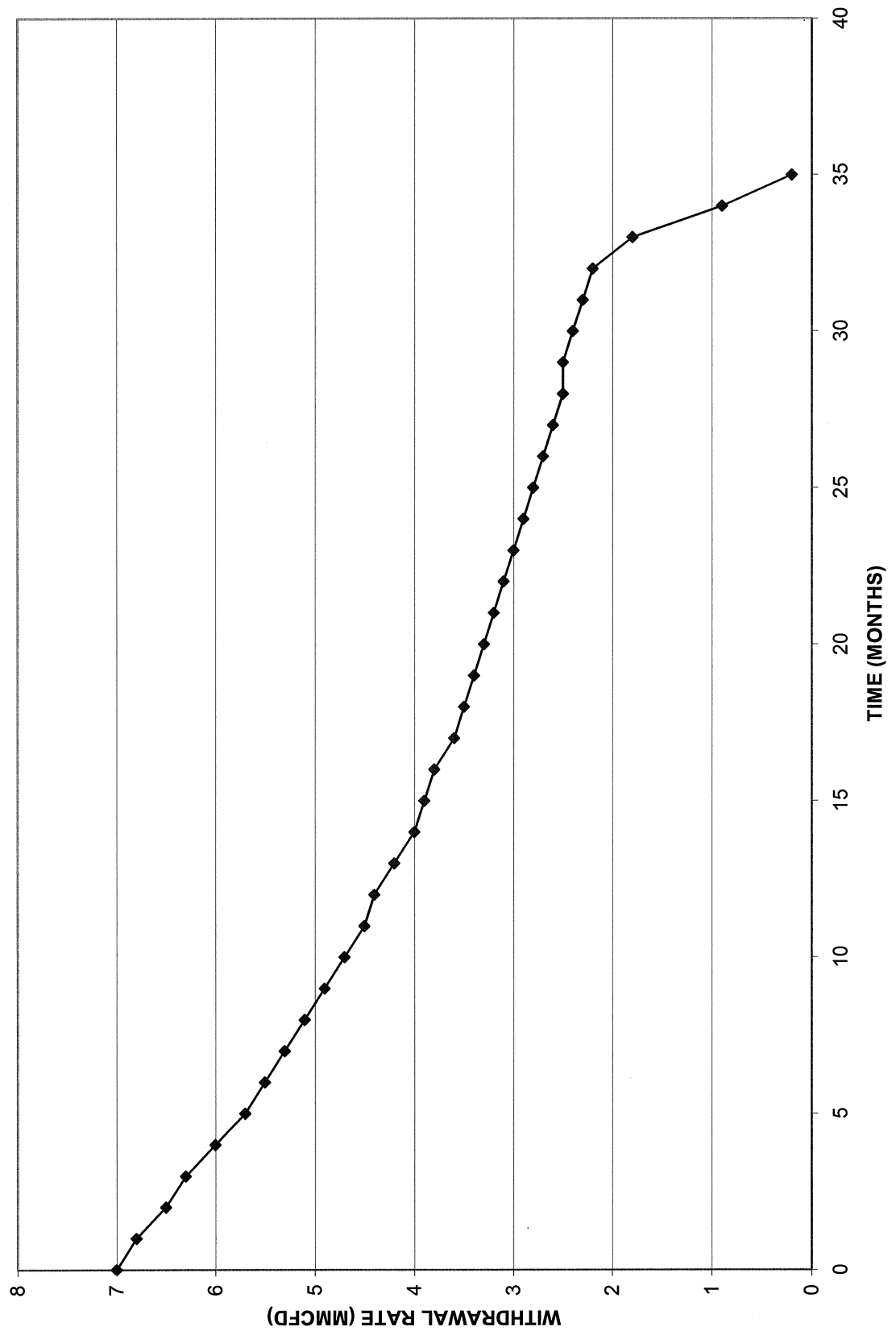
**SOUTHWEST GAS STORAGE COMPANY**  
**Determination of Economic Limit to Base Gas Production from Waverly Storage Field**

Capital to be amortized		\$0		Initial gas-in-place		51,620,081 Mcf				
Months of amortization		0		Base gas volume		46,620,081 Mcf				
Monthly operating expense		\$448,881		Working gas volume		5,000,000 Mcf				
				Time step		30 days				
Mo	Avg. Rate (Mcf/D)	Base Gas Production Monthly (Mcf)	Cum Production (Mcf)	Gas Price (Mcf)	Gross Economic Value (\$)	Operating Expenses (\$)	Fuel Costs (\$)	Amortization of Capital	Net Economic Value (\$)	Remaining Base Gas (Mcf)
1	4.5	4,500	135,081	\$7.94	\$1,072,543	\$448,881	\$21,451	\$0	\$602,211	46,485,000
2	3.0	3,000	90,000	\$7.94	\$714,600	\$448,881	\$14,292	\$0	\$251,427	46,395,000
3	2.5	2,500	75,000	\$7.94	\$595,500	\$448,881	\$11,910	\$0	\$134,709	46,320,000
4	1.5	1,500	45,000	\$7.94	\$357,300	\$448,881	\$7,146	\$0	-\$98,727	46,275,000

**SOUTHWEST GAS STORAGE COMPANY**  
**North Hopeton Storage Field – Rate and Pressure vs. Remaining Inventory**



**SOUTHWEST GAS STORAGE COMPANY**  
**North Hopeton Storage Field – Withdrawal Rate vs. Time**



**SOUTHWEST GAS STORAGE COMPANY**  
**Determination of Economic Limit to Base Gas Production from North Hopeton Storage Field**

Capital to be amortized		\$600,000 <sup>1</sup>	Initial gas-in-place		21,600,000 Mcf					
Months of amortization		12	Base gas volume		11,600,000 Mcf					
Monthly operating expense		\$155,220	Working gas volume		10,000,000 Mcf					
			Time step		30 days					
Notes: 1. Five wells are recompleted in the top of the Hunton when the field rate drops below 5 MMcfd										
Mo	Base Gas Production		Cum Production (Mcf)	Gas Price (\$/Mcf)	Gross Economic Value (\$)	Operating Expenses (\$)	Fuel Costs (\$)	Amortization of Capital	Net Economic Value (\$)	Remaining Base Gas (Mcf)
	Avg. Rate (Mcf/D)	Monthly (Mcf)								
1	6,800	204,000	204,000	\$7.94	\$1,619,760	\$155,220	\$0		\$1,464,540	11,396,000
2	6,500	195,000	399,000	\$7.94	\$1,548,300	\$155,220	\$0		\$1,393,080	11,201,000
3	6,300	189,000	588,000	\$7.94	\$1,500,660	\$155,220	\$0		\$1,345,440	11,012,000
4	6,000	180,000	768,000	\$7.94	\$1,429,200	\$155,220	\$0		\$1,273,980	10,832,000
5	5,700	171,000	939,000	\$7.94	\$1,357,740	\$155,220	\$0		\$1,202,520	10,661,000
6	5,500	165,000	1,104,000	\$7.94	\$1,310,100	\$155,220	\$0		\$1,154,880	10,496,000
7	5,300	159,000	1,263,000	\$7.94	\$1,262,460	\$155,220	\$0		\$1,107,240	10,337,000
8	5,100	153,000	1,416,000	\$7.94	\$1,214,820	\$155,220	\$0		\$1,059,600	10,184,000
9	4,900	147,000	1,563,000	\$7.94	\$1,167,180	\$155,220	\$0	\$50,000	\$961,960	10,037,000
10	4,700	141,000	1,704,000	\$7.94	\$1,119,540	\$155,220	\$0	\$50,000	\$914,320	9,896,000
11	4,500	135,000	1,839,000	\$7.94	\$1,071,900	\$155,220	\$0	\$50,000	\$866,680	9,761,000
12	4,400	132,000	1,971,000	\$7.94	\$1,048,080	\$155,220	\$0	\$50,000	\$842,860	9,629,000
13	4,200	126,000	2,097,000	\$7.94	\$1,000,440	\$155,220	\$0	\$50,000	\$795,220	9,503,000
14	4,000	120,000	2,217,000	\$7.94	\$952,800	\$155,220	\$0	\$50,000	\$747,580	9,383,000
15	3,900	117,000	2,334,000	\$7.94	\$928,980	\$155,220	\$0	\$50,000	\$723,760	9,266,000
16	3,800	114,000	2,448,000	\$7.94	\$905,160	\$155,220	\$0	\$50,000	\$699,940	9,152,000
17	3,600	108,000	2,556,000	\$7.94	\$857,520	\$155,220	\$0	\$50,000	\$652,300	9,044,000
18	3,500	105,000	2,661,000	\$7.94	\$833,700	\$155,220	\$0	\$50,000	\$628,480	8,939,000
19	3,400	102,000	2,763,000	\$7.94	\$809,880	\$155,220	\$0	\$50,000	\$604,660	8,837,000
20	3,300	99,000	2,862,000	\$7.94	\$786,060	\$155,220	\$0	\$50,000	\$580,840	8,738,000
21	3,200	96,000	2,958,000	\$7.94	\$762,240	\$155,220	\$0	\$0	\$607,020	8,642,000
22	3,100	93,000	3,051,000	\$7.94	\$738,420	\$155,220	\$0	\$0	\$583,200	8,549,000
23	3,000	90,000	3,141,000	\$7.94	\$714,600	\$155,220	\$0	\$0	\$559,380	8,459,000
24	2,900	87,000	3,228,000	\$7.94	\$690,780	\$155,220	\$0	\$0	\$535,560	8,372,000
25	2,800	84,000	3,312,000	\$7.94	\$666,960	\$155,220	\$0	\$0	\$511,740	8,288,000
26	2,700	81,000	3,393,000	\$7.94	\$643,140	\$155,220	\$0	\$0	\$487,920	8,207,000

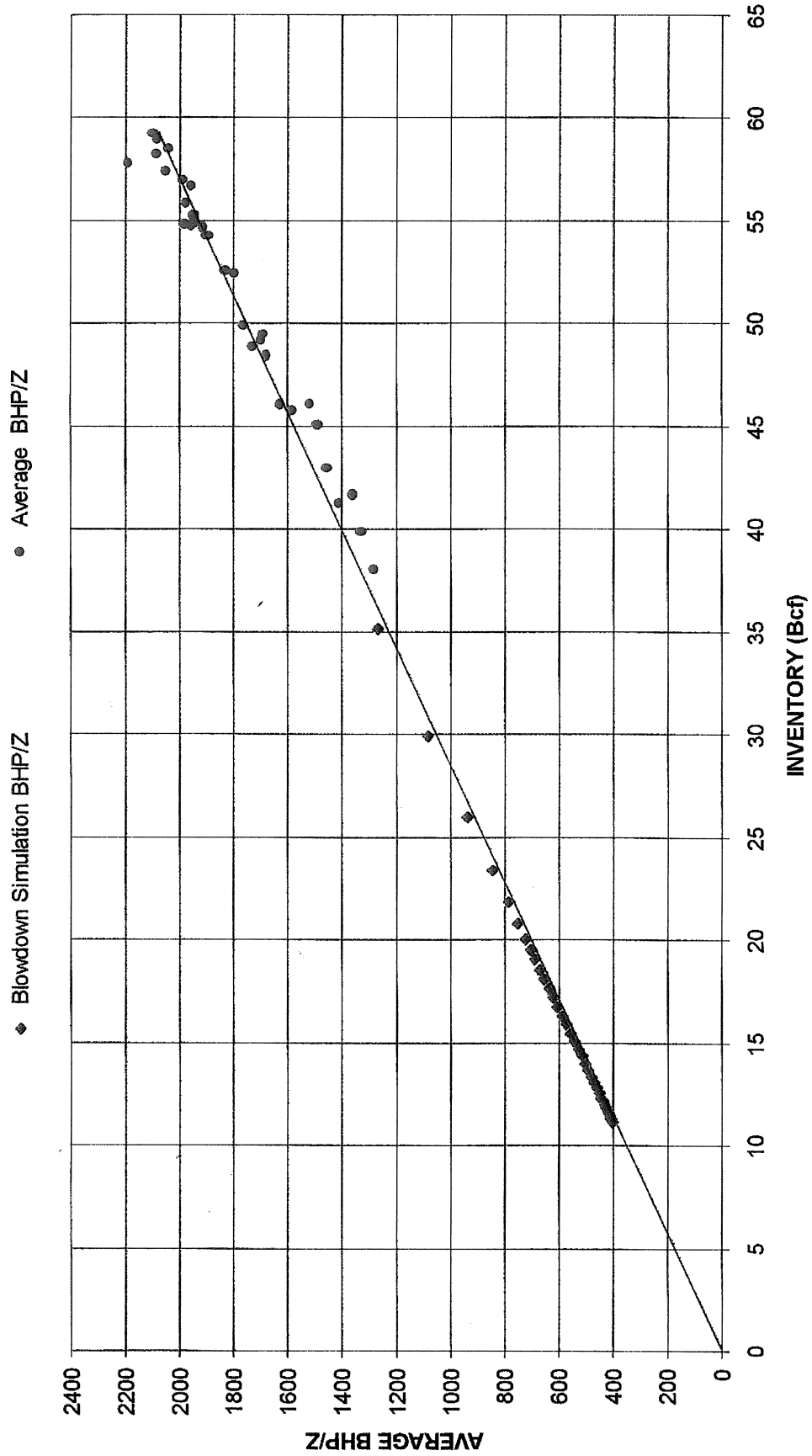
**SOUTHWEST GAS STORAGE COMPANY**  
**Determination of Economic Limit to Base Gas Production from North Hopeton Storage Field**

Mo	Base Gas Production		Cum Production (Mcf)	Gas Price (\$/Mcf)	Gross Economic Value (\$)	Operating Expenses (\$)	Fuel Costs (\$)	Amortization of Capital	Net Economic Value (\$)	Remaining Base Gas (Mcf)
	Avg. Rate (Mcf/D)	Monthly (Mcf)								
27	2,600	78,000	3,471,000	\$7.94	\$619,320	\$155,220	\$0		\$464,100	8,129,000
28	2,500	75,000	3,546,000	\$7.94	\$595,500	\$155,220	\$0		\$440,280	8,054,000
29	2,500	75,000	3,621,000	\$7.94	\$595,500	\$155,220	\$0		\$440,280	7,979,000
30	2,400	72,000	3,693,000	\$7.94	\$571,680	\$155,220	\$0		\$416,460	7,907,000
31	2,300	69,000	3,762,000	\$7.94	\$547,860	\$155,220	\$0		\$392,640	7,838,000
32	2,200	66,000	3,828,000	\$7.94	\$524,040	\$155,220	\$0		\$368,820	7,772,000
33	1,800	54,000	3,882,000	\$7.94	\$428,760	\$155,220	\$0		\$273,540	7,718,000
34	900	27,000	3,909,000	\$7.94	\$214,380	\$155,220	\$0		\$59,160	7,691,000
35	200	6,000	3,915,000	\$7.94	\$47,640	\$155,220	\$0		-\$107,580	7,685,000

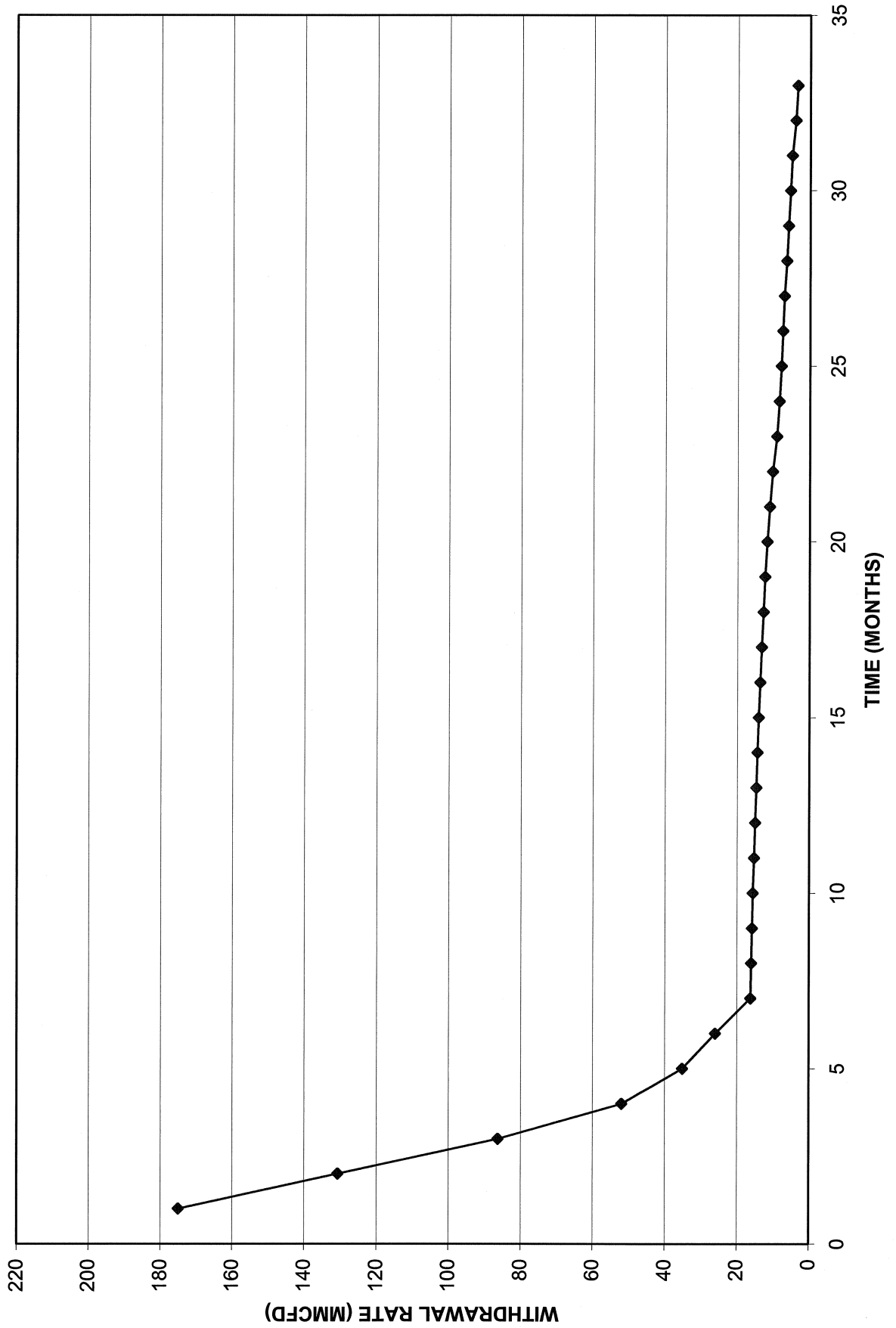
Economic  
limit

# SOUTHWEST GAS STORAGE COMPANY

## Borchers North Storage Field – BHP/Z vs. Inventory



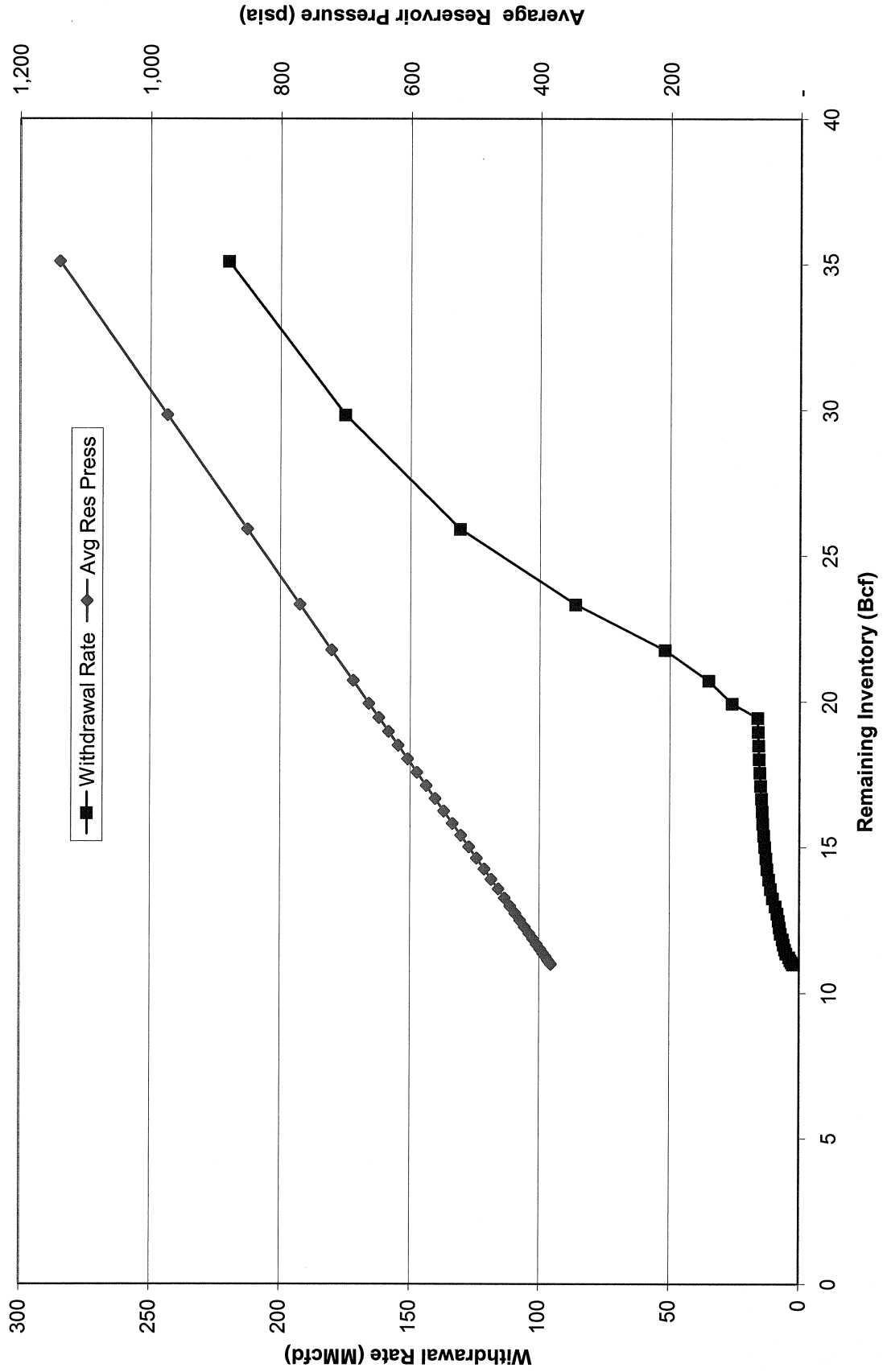
# **SOUTHWEST GAS STORAGE COMPANY** **Borchers North Storage Field – Withdrawal Rate vs. Time**





# SOUTHWEST GAS STORAGE COMPANY

## Borchers North Storage Field – Rate and Pressure vs. Remaining Inventory



**SOUTHWEST GAS STORAGE COMPANY**  
**Determination of Economic Limit to Base Gas Production from Borchers North Storage Field**

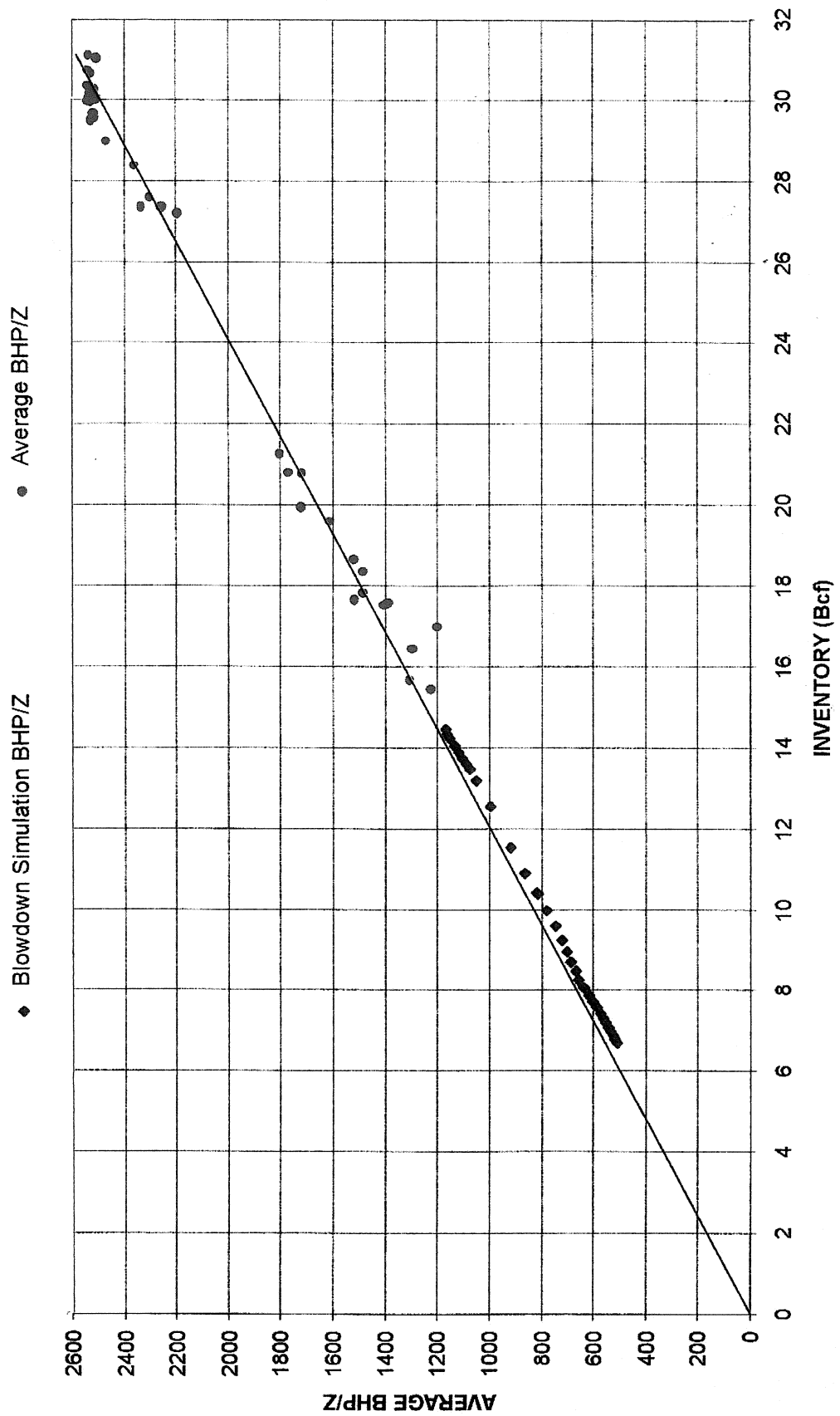
Capital to be amortized		\$996,000 <sup>2</sup>	Initial gas-in-place			71,200,000 Mcf				
Months of amortization		12	Base gas volume			35,081,226 Mcf				
Monthly operating expense		\$701,462 <sup>1</sup>	Working gas volume			28,300,000 Mcf				
			Time step			30 days				
Notes: 1. An additional monthly operating cost of \$15,000 per month is incurred after skid-mounted compression is installed										
2. Cost to deactivate old compression and install new compression amortized over 12 months										
Mo	Avg. Rate (Mcf/D)	Base Gas Production Monthly (Mcf)	Cum Production (Mcf)	Gas Price (\$/Mcf)	Gross Economic Value (\$)	Operating Expenses (\$)	Fuel Costs (\$)	Amortization of Capital	Net Economic Value (\$)	Remaining Base Gas (Mcf)
1	175,000	5,250,226	5,250,226	\$7.94	\$41,686,794	\$701,462	\$833,736		\$40,151,597	29,831,000
2	130,700	3,921,000	9,171,226	\$7.94	\$31,132,740	\$701,462	\$622,655		\$29,808,623	25,910,000
3	86,200	2,586,000	11,757,226	\$7.94	\$20,532,840	\$701,462	\$410,657		\$19,420,721	23,324,000
4	51,900	1,557,000	13,314,226	\$7.94	\$12,362,580	\$701,462	\$247,252		\$11,413,866	21,767,000
5	35,100	1,053,000	14,367,226	\$7.94	\$8,360,820	\$701,462	\$167,216		\$7,492,142	20,714,000
6	26,000	780,000	15,147,226	\$7.94	\$6,193,200	\$701,462	\$123,864		\$5,367,874	19,934,000
7	16,200	486,000	15,633,226	\$7.94	\$3,858,840	\$716,462	\$77,177	\$83,000	\$2,982,201	19,448,000
8	16,000	480,000	16,113,226	\$7.94	\$3,811,200	\$716,462	\$76,224	\$83,000	\$2,935,514	18,968,000
9	15,800	474,000	16,587,226	\$7.94	\$3,763,560	\$716,462	\$75,271	\$83,000	\$2,888,827	18,494,000
10	15,600	468,000	17,055,226	\$7.94	\$3,715,920	\$716,462	\$74,318	\$83,000	\$2,842,140	18,026,000
11	15,300	459,000	17,514,226	\$7.94	\$3,644,460	\$716,462	\$72,889	\$83,000	\$2,772,109	17,567,000
12	15,000	450,000	17,964,226	\$7.94	\$3,573,000	\$716,462	\$71,460	\$83,000	\$2,702,078	17,117,000
13	14,700	441,000	18,405,226	\$7.94	\$3,501,540	\$716,462	\$70,031	\$83,000	\$2,632,047	16,676,000
14	14,400	432,000	18,837,226	\$7.94	\$3,430,080	\$716,462	\$68,602	\$83,000	\$2,562,016	16,244,000
15	14,100	423,000	19,260,226	\$7.94	\$3,358,620	\$716,462	\$67,172	\$83,000	\$2,491,986	15,821,000
16	13,700	411,000	19,671,226	\$7.94	\$3,263,340	\$716,462	\$65,267	\$83,000	\$2,398,611	15,410,000
17	13,300	399,000	20,070,226	\$7.94	\$3,168,060	\$716,462	\$63,361	\$83,000	\$2,305,237	15,011,000
18	12,800	384,000	20,454,226	\$7.94	\$3,048,960	\$716,462	\$60,979	\$83,000	\$2,188,519	14,627,000
19	12,400	372,000	20,826,226	\$7.94	\$2,953,680	\$716,462	\$59,074		\$2,178,144	14,255,000
20	11,800	354,000	21,180,226	\$7.94	\$2,810,760	\$716,462	\$56,215		\$2,038,083	13,901,000
21	11,100	333,000	21,513,226	\$7.94	\$2,644,020	\$716,462	\$52,880		\$1,874,678	13,568,000
22	10,300	309,000	21,822,226	\$7.94	\$2,453,460	\$716,462	\$49,069		\$1,687,929	13,259,000
23	9,200	276,000	22,098,226	\$7.94	\$2,191,440	\$716,462	\$43,829		\$1,431,149	12,983,000
24	8,500	255,000	22,353,226	\$7.94	\$2,024,700	\$716,462	\$40,494		\$1,267,744	12,728,000
25	8,000	240,000	22,593,226	\$7.94	\$1,905,600	\$716,462	\$38,112		\$1,151,026	12,488,000
26	7,600	228,000	22,821,226	\$7.94	\$1,810,320	\$716,462	\$36,206		\$1,057,652	12,260,000
27	7,200	216,000	23,037,226	\$7.94	\$1,715,040	\$716,462	\$34,301		\$964,277	12,044,000

**SOUTHWEST GAS STORAGE COMPANY**  
**Determination of Economic Limit to Base Gas Production from Borchers North Storage Field**

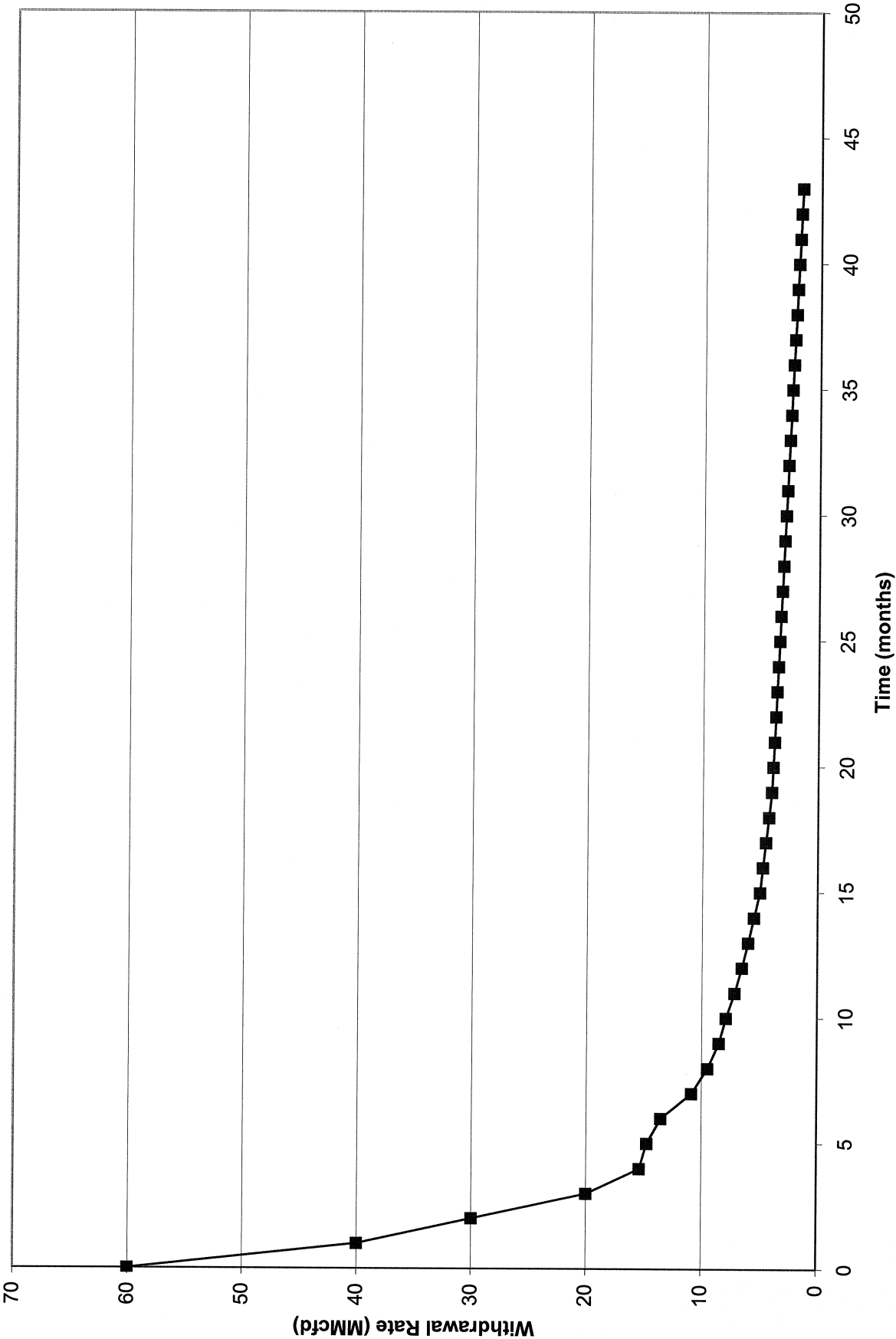
Mo	Base Gas Production		Cum Production (Mcf)	Gas Price \$/Mcf	Gross Economic Value (\$)	Operating Expenses (\$)	Fuel Costs (\$)	Amortization of Capital	Net Economic Value (\$)	Remaining Base Gas (Mcf)
	Avg. Rate (Mcf/D)	Monthly (Mcf)								
28	6,500	195,000	23,232,226	\$7.94	\$1,548,300	\$716,462	\$30,966		\$800,872	11,849,000
29	6,000	180,000	23,412,226	\$7.94	\$1,429,200	\$716,462	\$28,584		\$684,154	11,669,000
30	5,500	165,000	23,577,226	\$7.94	\$1,310,100	\$716,462	\$26,202		\$567,436	11,504,000
31	5,000	150,000	23,727,226	\$7.94	\$1,191,000	\$716,462	\$23,820		\$450,718	11,354,000
32	4,000	120,000	23,847,226	\$7.94	\$952,800	\$716,462	\$19,056		\$217,282	11,234,000
33	3,500	105,000	23,952,226	\$7.94	\$833,700	\$716,462	\$16,674		\$100,564	11,129,000
34	3,000	90,000	24,023,226	\$7.94	\$714,600	\$716,462	\$14,292		-\$16,154	11,058,000

Economic  
limit

# **SOUTHWEST GAS STORAGE COMPANY** **Howell Storage Field – BHP/Z vs. Inventory**

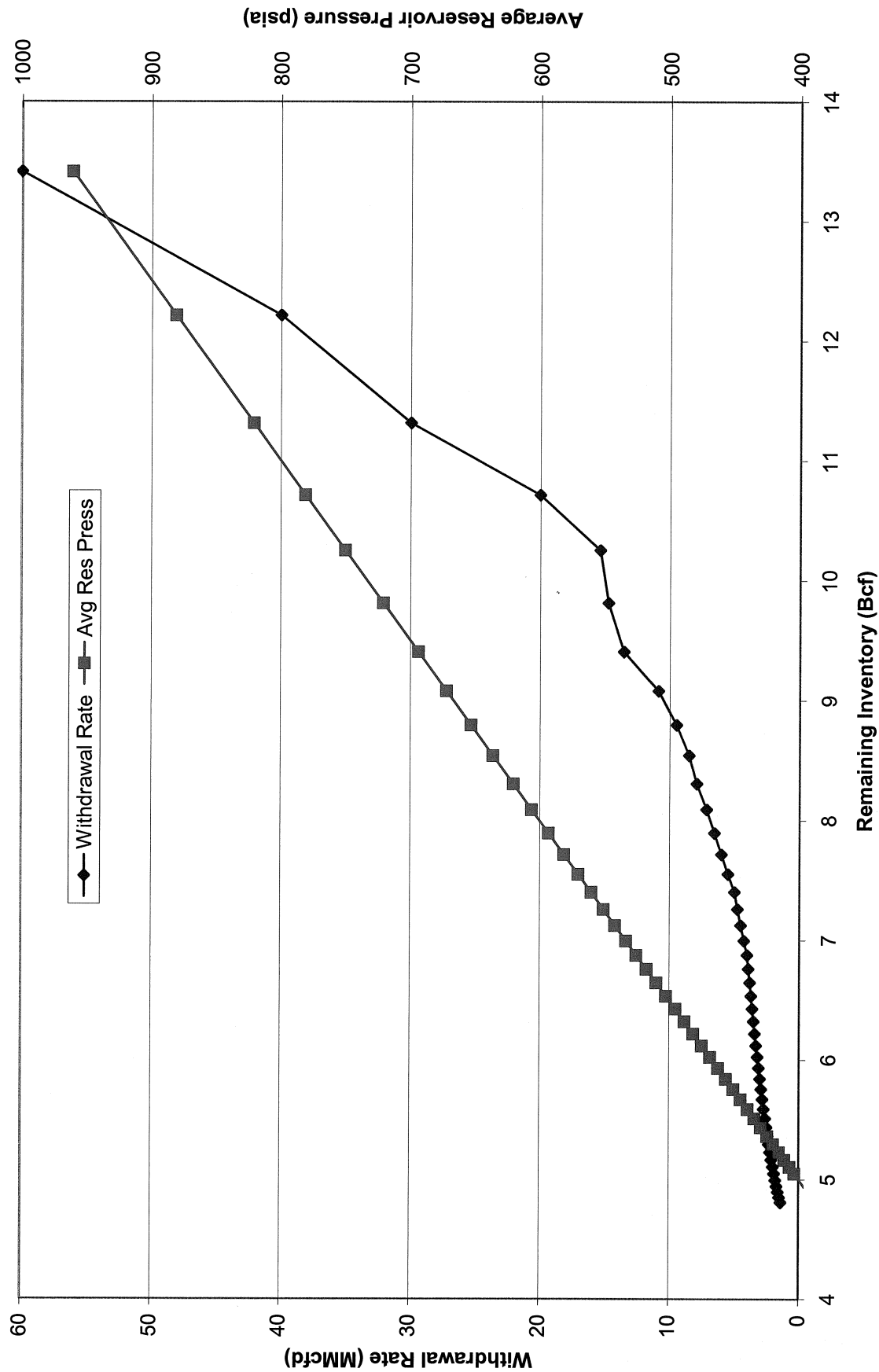


**SOUTHWEST GAS STORAGE COMPANY**  
**Howell Storage Field – Withdrawal Rate vs. Time**



# SOUTHWEST GAS STORAGE COMPANY

## Howell Storage Field – Rate and Pressure vs. Remaining Inventory



**SOUTHWEST GAS STORAGE COMPANY**  
**Determination of Economic Limit to Base Gas Production from Howell Storage Field**

Capital to be amortized		\$996,000 <sup>2</sup>	Initial gas-in-place			31,164,224 Mcf				
Months of amortization		12	Base gas volume			13,414,224 Mcf				
Monthly operating expense		\$350,000 <sup>1</sup>	Working gas volume			17,750,000 Mcf				
			Time step			30 days				
Notes: 1. An additional monthly operating cost of \$15,000 per month is incurred after skid-mounted compression is installed										
2. Cost to deactivate old compression and install new compression amortized over 12 months										
Mo	Base Gas Production		Cum Production (Mcf)	Gas Price (Mcf)	Gross Economic Value (\$)	Operating Expenses (\$)	Fuel Costs (\$)	Amortization of Capital	Net Economic Value (\$)	Remaining Base Gas (Mcf)
	Avg. Rate (Mcf/D)	Monthly (Mcf)								
1	40,000	1,200,624	1,200,624	\$7.94	\$9,532,955	\$350,000	\$190,659		\$8,992,295	12,213,600
2	30,000	900,000	2,100,624	\$7.94	\$7,146,000	\$350,000	\$142,920		\$6,653,080	11,313,600
3	20,000	600,000	2,700,624	\$7.94	\$4,764,000	\$350,000	\$95,280		\$4,318,720	10,713,600
4	15,350	460,500	3,161,124	\$7.94	\$3,656,370	\$350,000	\$73,127		\$3,233,243	10,253,100
5	14,713	441,400	3,602,524	\$7.94	\$3,504,716	\$365,000	\$70,094	\$83,000	\$2,986,622	9,811,700
6	13,527	405,800	4,008,324	\$7.94	\$3,222,052	\$365,000	\$64,441	\$83,000	\$2,709,611	9,405,900
7	10,860	325,800	4,334,124	\$7.94	\$2,586,852	\$365,000	\$51,737	\$83,000	\$2,087,115	9,080,100
8	9,460	283,800	4,617,924	\$7.94	\$2,253,372	\$365,000	\$45,067	\$83,000	\$1,760,305	8,796,300
9	8,497	254,900	4,872,824	\$7.94	\$2,023,906	\$365,000	\$40,478	\$83,000	\$1,535,428	8,541,400
10	7,883	236,500	5,109,324	\$7.94	\$1,877,810	\$365,000	\$37,556	\$83,000	\$1,392,254	8,304,900
11	7,140	214,200	5,323,524	\$7.94	\$1,700,748	\$365,000	\$34,015	\$83,000	\$1,218,733	8,090,700
12	6,533	196,000	5,519,524	\$7.94	\$1,556,240	\$365,000	\$31,125	\$83,000	\$1,077,115	7,894,700
13	5,990	179,700	5,699,224	\$7.94	\$1,426,818	\$365,000	\$28,536	\$83,000	\$950,282	7,715,000
14	5,500	165,000	5,864,224	\$7.94	\$1,310,100	\$365,000	\$26,202	\$83,000	\$835,898	7,550,000
15	5,000	150,000	6,014,224	\$7.94	\$1,191,000	\$365,000	\$23,820	\$83,000	\$719,180	7,400,000
16	4,750	142,500	6,156,724	\$7.94	\$1,131,450	\$365,000	\$22,629	\$83,000	\$660,821	7,257,500
17	4,500	135,000	6,291,724	\$7.94	\$1,071,900	\$365,000	\$21,438		\$685,462	7,122,500
18	4,250	127,500	6,419,224	\$7.94	\$1,012,350	\$365,000	\$20,247		\$627,103	6,995,000
19	4,000	120,000	6,539,224	\$7.94	\$952,800	\$365,000	\$19,056		\$568,744	6,875,000
20	3,900	117,000	6,656,224	\$7.94	\$928,980	\$365,000	\$18,580		\$545,400	6,758,000
21	3,800	114,000	6,770,224	\$7.94	\$905,160	\$365,000	\$18,103		\$522,057	6,644,000
22	3,700	111,000	6,881,224	\$7.94	\$881,340	\$365,000	\$17,627		\$498,713	6,533,000
23	3,600	108,000	6,989,224	\$7.94	\$857,520	\$365,000	\$17,150		\$475,370	6,425,000
24	3,500	105,000	7,094,224	\$7.94	\$833,700	\$365,000	\$16,674		\$452,026	6,320,000
25	3,400	102,000	7,196,224	\$7.94	\$809,880	\$365,000	\$16,198		\$428,682	6,218,000

**SOUTHWEST GAS STORAGE COMPANY**  
**Determination of Economic Limit to Base Gas Production from Howell Storage Field**

Mo	Base Gas Production		Cum Production (Mcf)	Gas Price (Mcf)	Gross Economic Value (\$)	Operating Expenses (\$)	Fuel Costs (\$)	Amortization of Capital	Net Economic Value (\$)	Remaining Base Gas (Mcf)
	Avg. Rate (Mcf/D)	Monthly (Mcf)								
26	3,300	99,000	7,295,224	\$7.94	\$786,060	\$365,000	\$15,721		\$405,339	6,119,000
27	3,200	96,000	7,391,224	\$7.94	\$762,240	\$365,000	\$15,245		\$381,995	6,023,000
28	3,100	93,000	7,484,224	\$7.94	\$738,420	\$365,000	\$14,768		\$358,652	5,930,000
29	3,000	90,000	7,574,224	\$7.94	\$714,600	\$365,000	\$14,292		\$335,308	5,840,000
30	2,900	87,000	7,661,224	\$7.94	\$690,780	\$365,000	\$13,816		\$311,964	5,753,000
31	2,800	84,000	7,745,224	\$7.94	\$666,960	\$365,000	\$13,339		\$288,621	5,669,000
32	2,700	81,000	7,826,224	\$7.94	\$643,140	\$365,000	\$12,863		\$265,277	5,588,000
33	2,600	78,000	7,904,224	\$7.94	\$619,320	\$365,000	\$12,386		\$241,934	5,510,000
34	2,500	75,000	7,979,224	\$7.94	\$595,500	\$365,000	\$11,910		\$218,590	5,435,000
35	2,400	72,000	8,051,224	\$7.94	\$571,680	\$365,000	\$11,434		\$195,246	5,363,000
36	2,300	69,000	8,120,224	\$7.94	\$547,860	\$365,000	\$10,957		\$171,903	5,294,000
37	2,200	66,000	8,186,224	\$7.94	\$524,040	\$365,000	\$10,481		\$148,559	5,228,000
38	2,100	63,000	8,249,224	\$7.94	\$500,220	\$365,000	\$10,004		\$125,216	5,165,000
39	2,000	60,000	8,309,224	\$7.94	\$476,400	\$365,000	\$9,528		\$101,872	5,105,000
40	1,900	57,000	8,366,224	\$7.94	\$452,580	\$365,000	\$9,052		\$78,528	5,048,000
41	1,800	54,000	8,420,224	\$7.94	\$428,760	\$365,000	\$8,575		\$55,185	4,994,000
42	1,700	51,000	8,471,224	\$7.94	\$404,940	\$365,000	\$8,099		\$31,841	4,943,000
43	1,600	48,000	8,519,224	\$7.94	\$381,120	\$365,000	\$7,622		\$8,498	4,895,000
44	1,500	45,000	8,564,224	\$7.94	\$357,300	\$365,000	\$7,146		-\$14,846	4,850,000

Economic  
limit