McDep Associates
Independent Stock Idea
April 2, 2003

Rating: Buy
S&P 500: 858

San Juan Basin Royalty Trust (SJT)
Continue Buy on Natural Gas Reserve Disclosures

Symbol	Price ($/sh) 1-Apr 2003	Shares (mm)	Market Cap ($mm)	Net Present Value ($/sh)	Debt/ Present Value	McDep Ratio	EV/ Sales NTM	EV/ Ebitda NTM	P/E NTM	Div'd NTM (%)	PV/ Ebitda NTM
SJT	14.67	46.6	680	17.40	-	0.84	5.0	6.2	7.2	14.0	7.4

McDep Ratio = **M**arket **c**ap and **De**bt to **p**resent value of oil and gas and other businesses

EV = Enterprise Value = Market Cap and Debt:	US$mm	680
Ebitda = Earnings before interest, tax, depreciation and amortization:	US$mm	110
NTM = Next Twelve Months Ended March 31, 2003; P/E = Stock Price to Earnings		
PV = Present Value of energy businesses:	US$mm	810

Summary and Recommendation

We continue to recommend current purchase of the units of San Juan Basin Royalty Trust as an attractively valued, zero debt, efficient participation in the income generation and appreciation potential of long life indigenous natural gas resources. Recently disclosed estimates of natural gas reserves as of the end of 2002 are up a third from the previous year. Excluding the effect of commodity price that has a dramatic impact on reported reserves, development spending has replaced 124% of production for the past three years. The cost of developing reserves having an average value of more than $1.54 per thousand cubic feet (mcf) was only about $0.56. Any operating company would be proud of those results as few can match such performance. We explain how we draw those conclusions from the factual report of the trustee and the conservative presentation of the independent engineer. Meanwhile taxable investors who purchased units at the beginning of 2002 would owe no tax on 2002 income. Finally there are political, economic and business risks in SJT as in any investment.

Undeveloped Reserves Understated

If commodity price is the most important industry variable that affects the value of natural gas producer investments, reserve life is the most important factor that differentiates one producer from another once we have an estimate of Next Twelve Months (NTM) cash flow. Our weekly estimates of present value incorporate total production to 2030 that can be considered as a reserve estimate. The trust's engineer discloses estimates annually at this time (see table).

Natural Gas and Oil Reserves

	SJT Engineer Natural Gas (bcf)	*Oil (mmb)*	*Total (bcf)*	*McDep (bcf)*
Reserves (bcf or mmb)				
Proven (P)	235	0.45	238	525
Proven Developed (PD)	210	0.42	212	315
Proven Undeveloped (PUD)	25	0.04	25	210
Production, Next Twelve Months				35
Reserve Life Index (years)				
R/P P				15.1
R/P PD				9.1
R/P PUD				6.0
R/P PD+.5PUD				12.1

The engineer's estimates are presented in Form 10-K filed by the trustee with the Securities and Exchange Commission. Our estimates are from Table SJT-1 as it appears in *Natural Gas Royalty Trusts* and at the end of this analysis. Although the engineer's reserves appear to be less than our estimates, that is not entirely the case.

The engineer estimates reserves on a net profits royalty basis while our estimates are on a working interest basis as is the common practice for operating companies. When we make that adjustment we see that the engineer's estimate for proven developed reserves is close to our estimate (see table).

Reserves Reconciliation

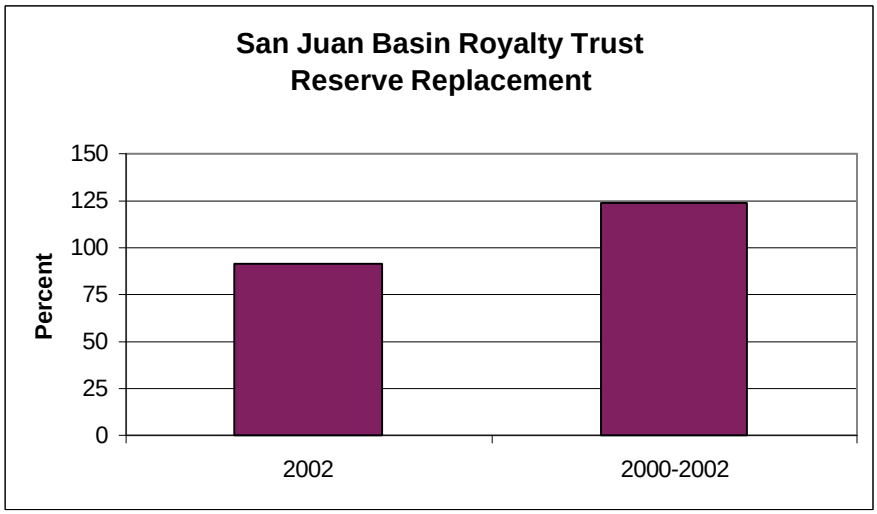
	SJT Engineer	McDep Royalty Interest	Royalty/ Working Interest	McDep Working Interest
Proven Developed (bcf)	210	211	0.67	315
Proven Undeveloped (bcf)	25	119	0.56	210
Total Proven (bcf)	235	330	0.63	525
Percent PUD	11	36		40

The main difference between the engineer's estimate and our estimate is in undeveloped reserves. The engineer estimates undeveloped reserves, also known as PUD's, at just 11% of total proven reserves. The industry average is closer to 30%. Our 40% is above the industry average because we believe that a giant basin like San Juan has more hidden potential than a typical gas field. After some 50 years of development the San Juan Basin

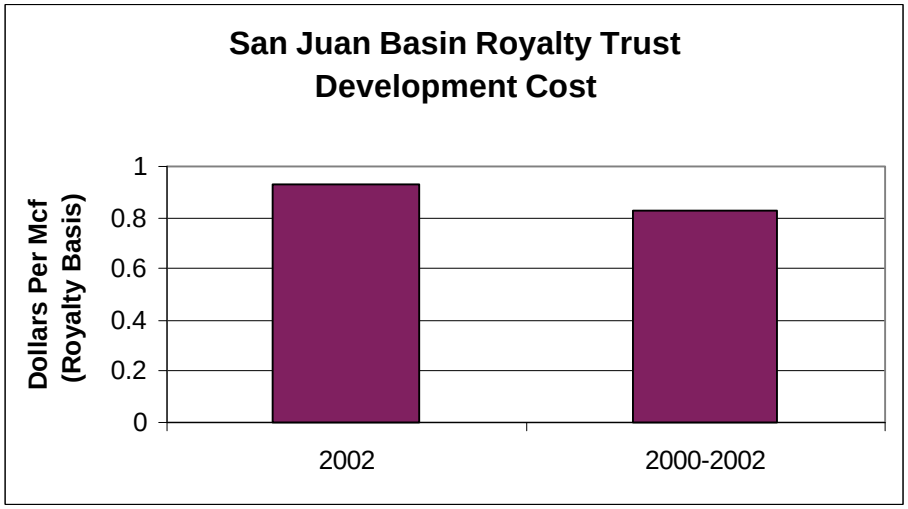
is producing more annually than almost any time in the past and has become the largest gas field in the contiguous United States.

Annual Production Replaced in New Reserves at Low Cost

Apparently the engineer is only willing to count those undeveloped reserves that could be developed mostly in the one-year period for which the operator, **Burlington Resources (BR)**, has communicated a budget to the trust. The reserve replacement record seems to attest to that (see chart). New reserves have exceeded production for the past three years.



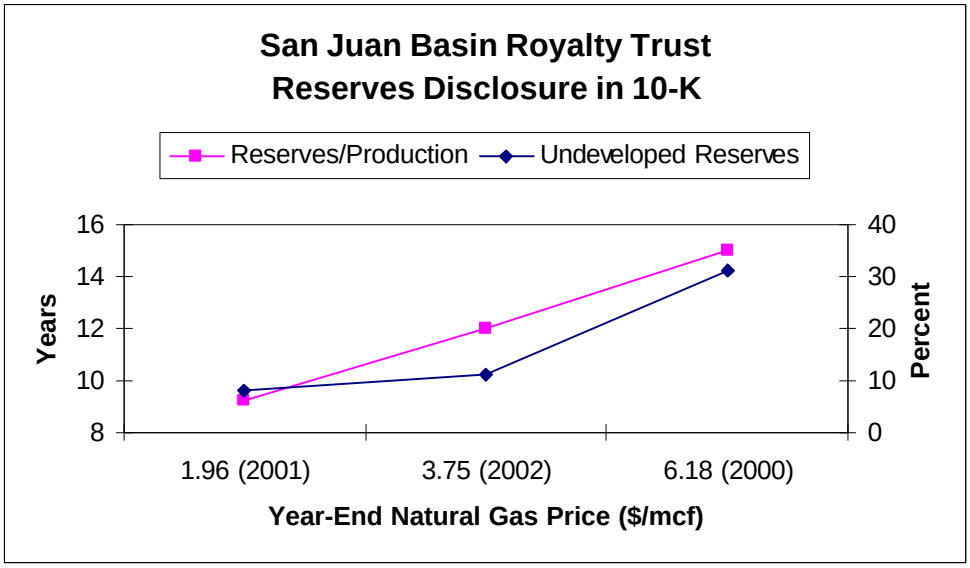
Moreover, the trust has been able to replace reserves while dedicating only 25% of cash flow to the effort. Moderate outlays for solid results imply low development cost of only $0.83 per mcf for three years (see Chart). That is equivalent to some $0.56 on a working interest basis.



Official Reserves and Present Value Sensitive to Commodity Price

The shape of the future in reserve estimation is in our work. There has always been a need for an objective price forecast in making reserve estimates. Decades ago the standards makers compromised on latest year end price as the basis for required estimates to be disclosed by publicly traded oil and gas producers. While that standard meets the test for objectivity, it necessarily can swing widely from year to year. Increasingly long-term commodity markets are getting more developed publicly. Eventually the standard for public reserve estimates is likely to go in the direction of using longer-term futures as the indicator of price as we use in our work.

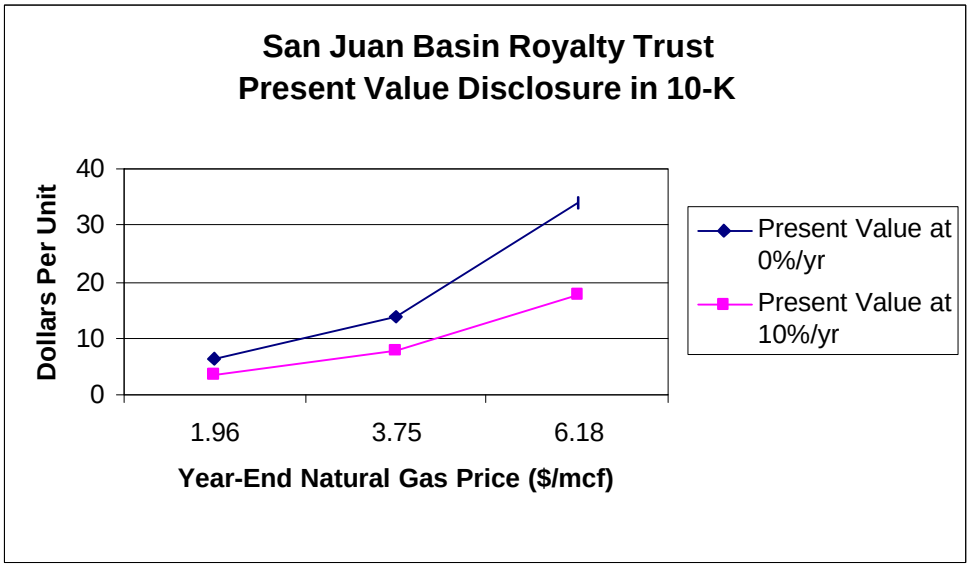
Yet there is a benefit in the wide price swings of the past few years. We can plot estimates of reserves by commodity price. Both reserve life and proportion of undeveloped reserves increase with commodity price (see Chart).



In the end the answer we are looking for is present value, but we want to be careful how we use the engineer's estimate. Two factors we want to vary are discount rate and commodity price. On the former, the engineer gives us two numbers at the end of a range from 0% to 10% per year. On the latter we can see how much the estimates have changed with the commodity price used in each of the past three years (see Chart).

The engineer's estimate of present value corresponds with ours after we take account of discount rate and commodity price and allow for the engineer's more conservative estimate of undeveloped reserves. To apply our discount rate of about 6% we can interpolate between the 0% and 10% values the engineer discloses. We also see the average price in our calculation is $3.99 per mcf. We need to increase that price to about $4.50 to get the equivalent to the price plotted. Thus, by further interpolation we might

conclude that the engineer's present value at a discount rate near 6% and recent time pattern of commodity futures prices near $4.50 would be about $14 a unit. That is close to the current market price of the units, but less than our present value of $17.40. The remaining difference might be largely explained by our expectation that development activity will continue beyond more than just one year.



The recent disclosures tend to confirm to us that our valuation analysis is reasonably consistent with today's commodity market. The larger question remains as to tomorrow's commodity market. Fully cognizant of our inability to know the future, we nonetheless believe that futures markets understate the likely future price of natural gas. Our trend case is for futures prices to be 50% higher than we use in our valuation calculations today. We don't need those prices for a successful investment, but such prospects help us keep perspective as we discuss today's details.

New Waves of Infill Drilling Under Way

The spacing of wells in the San Juan Basin has gradually become denser over the past fifty years. The New Mexico Oil Conservation Division establishes the rules for spacing. Development of the Mesa Verde formation, one of the two most important sources of conventional gas, has been proceeding on 80 acre spacing since 1997. In February 2002 the state agency approved 80 acre well spacing for the deeper Dakota formation, the other most important source of conventional gas. In October 2002 the regulators approved 80 acre spacing selectively for the Fruitland Coal formation the source of unconventional gas that accounted for 23% of the trust's production last year by heating value. Each regulatory decision unlocks years of drilling potential.

Depletion Defers Income Taxation

Taxable investors need to report royalty trust income in just six lines on the Federal return. We show an example for the purchase of 100 shares at the beginning of last year (see table). The calculation is explained in a booklet sent by the trustee to investors and available on www.sjbrt.com.

San Juan Basin Royalty Trust
Sample Tax Calculation

	Units		100
	Date of purchase		1/4/02
	Beginning of year cost basis	$	955
	Cost depletion factor		0.110
	Depletion	$	105
Schedule E			
Line 4	Royalties received	$	90
Line 16	Taxes	$	8
Line 18	Administration expense	$	4
Line 20	Depletion	$	105
	Royalty income	$	(27)
Schedule B	Interest income	$	0
Form 1040			
Line 53	Nonconventional source fuel credit	$	12

The most important feature of the calculation is that depletion offsets all of taxable income in this case. The next most important feature is that a tax credit is generated that can be used to offset taxable income from other sources under certain conditions. Finally there is the near trivial feature that is not obvious in the example. Income attributable to a calendar year is related to distributions declared from January to December, but paid from February to January.

Payments may also be owed to the State of New Mexico by taxable investors. Practically speaking, taxpayers might ignore that requirement when no taxable income is generated. In years of high income as we think lie ahead and as cost basis gets more depleted, New Mexico appears entitled to a share of the income in addition to the severance tax it also receives (Line 16). Native Americans and the Federal Government have also earned royalties not shown.

Kurt H. Wulff, CFA

Table SJT-1
San Juan Basin Royalty Trust
Present Value

Volume Decline (%/yr):	11	Price Escalation Post 2008 (%/yr):	2.7
Volume Enhancement (%/yr):	10	Discount rate (%/yr):	5.9
Capex/Cash Flow (%):	25	U.S. TIPS Inflation (%/yr):	1.9
Variable Cost (%):	12	U.S. 10 Year Yield (%/yr):	3.9
PV/Volume ($/mcf):	1.54	PV/EBITDA 2004:	7.5

Year	Volume Basic (bcf)	Volume Enhanced (bcf)	Total (bcf)	Price ($/mcf)	Revenue ($mm)	Fixed Cost ($mm)	Var Cost ($mm)	Cap Ex ($mm)	Distribution ($mm)	Distribution ($/unit)	Disc Factor	Present Value ($/unit)
Total 2004 through 2030; years ending on 3/31												
	315	210	525	3.99	2094	350	251	179	1315	28.22	0.62	17.40
2004	35.1	0.0	35.1	3.87	135.9	11.6	16.3	12.5	95.4	2.05	0.97	1.99
2005	31.4	3.5	34.9	3.84	134.1	13.0	16.1	26.3	78.8	1.69	0.92	1.55
2006	28.1	6.6	34.7	3.63	126.0	13.0	15.1	24.5	73.4	1.57	0.87	1.36
2007	25.1	9.4	34.5	3.45	119.2	13.0	14.3	23.0	68.9	1.48	0.82	1.21
2008	22.4	11.9	34.3	3.45	118.3	13.0	14.2	22.8	68.4	1.47	0.77	1.13
2009	20.1	14.0	34.1	3.45	117.7	13.0	14.1	22.7	68.0	1.46	0.73	1.06
2010	17.9	15.9	33.9	3.55	120.2	13.0	14.4	23.2	69.6	1.49	0.69	1.03
2011	16.0	17.6	33.7	3.64	122.6	13.0	14.7	23.7	71.2	1.53	0.65	0.99
2012	14.3	15.8	30.1	3.74	112.5	13.0	13.5		86.0	1.85	0.61	1.13
2013	12.8	14.1	26.9	3.84	103.3	13.0	12.4		77.9	1.67	0.58	0.97
2014	11.5	12.6	24.1	3.94	94.8	13.0	11.4		70.4	1.51	0.55	0.83
2015	10.2	11.3	21.5	4.04	87.0	13.0	10.4		63.6	1.36	0.52	0.70
2016	9.2	10.1	19.2	4.15	79.8	13.0	9.6		57.3	1.23	0.49	0.60
2017	8.2	9.0	17.2	4.26	73.3	13.0	8.8		51.5	1.10	0.46	0.51
2018	7.3	8.1	15.4	4.37	67.3	13.0	8.1		46.2	0.99	0.43	0.43
2019	6.5	7.2	13.7	4.49	61.7	13.0	7.4		41.3	0.89	0.41	0.36
2020	5.8	6.4	12.3	4.61	56.6	13.0	6.8		36.8	0.79	0.39	0.31
2021	5.2	5.8	11.0	4.73	52.0	13.0	6.2		32.8	0.70	0.36	0.26
2022	4.7	5.1	9.8	4.86	47.7	13.0	5.7		29.0	0.62	0.34	0.21
2023	4.2	4.6	8.8	4.99	43.8	13.0	5.3		25.5	0.55	0.33	0.18
2024	3.7	4.1	7.8	5.12	40.2	13.0	4.8		22.4	0.48	0.31	0.15
2025	3.3	3.7	7.0	5.26	36.9	13.0	4.4		19.5	0.42	0.29	0.12
2026	3.0	3.3	6.3	5.40	33.9	13.0	4.1		16.8	0.36	0.27	0.10
2027	2.7	2.9	5.6	5.54	31.1	13.0	3.7		14.3	0.31	0.26	0.08
2028	2.4	2.6	5.0	5.69	28.5	13.0	3.4		12.1	0.26	0.24	0.06
2029	2.1	2.3	4.5	5.84	26.2	13.0	3.1		10.0	0.22	0.23	0.05
2030	1.9	2.1	4.0	5.99	24.0	13.0	2.9		8.1	0.17	0.22	0.04

Table SJT-2
San Juan Basin Royalty Trust
Distributable Income

	Q2	*Q3*	*Q4*	*Year*	*Q1E*	*Q2E*	*Q3E*	*Q4E*	*Year*	*Q1E*	***Next Twelve***
	6/30/02	*9/30/02*	*12/31/02*	*2002*	*3/31/03*	*6/30/03*	*9/30/03*	*12/31/03*	*2003E*	*3/31/04*	*Months 3/31/04*
Highlights											
Revenue ($mm) (75%)	18.6	20.7	20.4	78.9	31.1	39.1	32.1	31.8	134.1	32.9	135.9
Cash flow ($mm) (75%)	14.1	16.0	15.6	59.7	25.0	32.3	25.8	25.6	108.7	26.6	110.3
Per unit	0.30	0.34	0.33	1.28	0.54	0.69	0.55	0.55	2.33	0.57	2.37
Tax credit ($mm)	1.4	1.9	1.9	5.6					-		
Per unit	0.03	0.04	0.04	0.12					-		
Distributable Income ($mm)	9.0	12.2	11.6	36.3	19.5	28.6	22.1	21.9	92.1	22.8	95.4
Per unit	0.19	0.26	0.25	0.78	0.42	0.61	0.47	0.47	1.98	0.49	2.05
Units (millions)	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6
Volume											
Natural gas (mmbtu)	12.0	11.6	12.4	48.5	12.6	11.8	12.2	12.2	49.0	12.2	48.6
Heat Content(btu/cf)	1,077	970	1,064	1,050	1,084	1,048	1,048	1,048	1,057	1,048	1,048
Natural gas (bcf)	11.1	12.0	11.6	46.2	11.6	11.3	11.7	11.7	46.3	11.7	46.4
Natural Gas (mmcfd)	125.1	130.4	126.2	126.6	126.5	127.0	127.0	127.0	126.9	127.0	127.0
Days	89	92	92	365	92	89	92	92	365	92	365
Oil (mb)	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1
Oil (mbd)	0.3	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total gas & oil (bcf)	11.3	12.1	11.7	46.8	11.8	11.4	11.8	11.8	46.8	11.8	46.8
Price											
Natural gas ($/mmbtu) (Henry Hub lagged two months)											
Henry Hub ($/mmbtu)	2.92	3.23	3.59	3.02	4.73	6.27	5.15	5.11	5.31	5.29	5.45
Differential (%)	31	28	40	30	32	31	33	33	32	33	32
Total	2.02	2.33	2.16	2.13	3.24	4.34	3.45	3.43	3.61	3.54	3.68
Natural gas ($/mcf)	2.18	2.26	2.30	2.24	3.51	4.55	3.61	3.59	3.81	3.71	3.86
Oil ($/bbl) (WTI Cushing lagged two months)											
WTI Cushing	23.80	26.49	28.96	24.70	29.55	32.72	27.23	25.64	28.78	25.00	27.65
SJT	19.14	21.95	28.35	20.90	28.92	32.03	26.65	25.10	28.14	24.47	27.02
Total gas & oil ($/mcf)	2.19	2.28	2.32	2.25	3.53	4.56	3.62	3.60	3.82	3.72	3.87
Revenue ($mm)											
Natural Gas	24.2	27.1	26.7	103.3	40.9	51.5	42.2	42.0	176.6	43.4	179.1
Oil	0.5	0.5	0.6	2.0	0.6	0.6	0.5	0.5	2.2	0.5	2.1
Total	24.8	27.6	27.3	105.2	41.5	52.1	42.8	42.5	178.8	43.9	181.2
Cost ($mm)											
Severance tax	2.4	2.3	3.1	10.5	4.2	5.2	4.3	4.2	17.9	4.4	18.1
Operating	3.7	4.0	3.4	15.2	3.9	3.7	4.1	4.1	15.8	4.1	16.0
Total	6.0	6.3	6.5	25.6	8.1	8.9	8.4	8.3	33.8	8.5	34.1
Cash flow ($mm)	18.8	21.3	20.7	79.6	33.3	43.1	34.4	34.1	145.0	35.4	147.0
Development	3.4	2.1	4.7	21.5	6.6	4.2	4.2	4.2	19.1	4.2	16.7
Net proceeds ($mm)	15.4	19.2	16.1	58.2	26.8	39.0	30.2	29.9	125.9	31.2	130.3
Royalty income ($mm)	11.5	14.4	12.1	43.6	20.1	29.2	22.7	22.5	94.4	23.4	97.7
Royalty/Net proceeds	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Administration	0.5	0.6	0.5	2.0	0.6	0.6	0.6	0.6	2.3	0.6	2.4
One-time	2.0	1.6		5.3					-		-
Distributable income ($mm)	9.0	12.2	11.6	36.3	19.5	28.6	22.1	21.9	92.1	22.8	95.4
Modeling ratios											
Severance tax/revenue	9.5%	8.5%	11.5%	9.9%	10.2%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Operating cost ($/mcf)	0.32	0.33	0.29	0.32	0.33	0.33	0.35	0.35	0.34	0.35	0.34
Development/Cash flow	18%	10%	22%	27%	20%	10%	12%	12%	13%	12%	11%

Table SJT-3
San Juan Basin Royalty Trust
Monthly Declarations

	Dec-02	*Jan-03*	*Feb-03*	*Mar-03*	*Apr-03*	*May-03*	*Jun-03*
Distribution ($/unit)							
Declared	0.09	0.10	0.12	0.20			
Projected					*0.18*	*0.27*	*0.16*
Volume							
Natural gas (mmbtu)	4.08	4.07	3.97	4.58	3.73	4.13	3.99
Heat Content(btu/cf)	1,043	1,092	1,097	1,067	1,048	1,048	1,048
Natural gas (bcf)	3.91	3.73	3.62	4.29	3.56	3.94	3.81
Natural Gas (mmcfd)	126	124	117	138	127	127	127
Days	31	30	31	31	28	31	30
Price							
Natural gas industry quotes lagged two months ($/mmbtu)							
Henry Hub Daily/Futures	4.12	4.03	4.76	5.41	7.77	5.97	5.06
San Juan Monthly Index	2.52	3.25	3.45	4.14	4.58	5.91	
SJT/Henry Hub	0.54	0.71	0.66	0.68	0.53	0.89	0.70
SJT/San Juan Index	0.89	0.88	0.91	0.88	0.90	0.90	
SJT ($/mmbtu)	2.24	2.85	3.14	3.66	4.12	5.32	3.54
SJT ($/mcf)	2.33	3.12	3.45	3.91	4.32	5.57	3.71
Revenue ($mm)							
Natural Gas	9.1	11.6	12.5	16.8	15.4	22.0	14.1
Other	0.0	0.1	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Cost ($mm)							
Severance tax	1.5	1.2	1.3	1.7	1.6	2.2	1.4
Operating	0.5	1.5	1.3	1.1	1.2	1.2	1.2
Total	2.0	2.7	2.6	2.8	2.8	3.5	2.7
Cash flow ($mm)	7.1	9.0	9.8	13.8	12.5	18.4	11.4
Development	1.6	2.7	2.4	1.4	1.4	1.4	1.4
Net proceeds ($mm)	5.5	6.3	7.4	12.4	11.1	17.0	10.0
Royalty income ($mm)	4.2	4.7	5.5	9.3	8.3	12.8	7.5
Royalty/Net proceeds	75%	75%	75%	75%	75%	75%	75%
One time							
Distributable income ($mm)	4.2	4.7	5.5	9.3	8.3	12.8	7.5
Units (millions)	46.6	46.6	46.6	46.6	46.6	46.6	46.6
Distribution ($/unit)	0.09	0.10	0.12	0.20	0.18	0.27	0.16
Latest Twelve Month Average							
Heat Content(btu/cf)	1,050	1,050	1,050	1,048			
Natural Gas (mmcfd)	127	127	126	127			
SJT/Henry Hub	0.72	0.70	0.70	0.67			
SJT/San Juan Index	0.88	0.89	0.90	0.90			
Other revenue	(0.2)	(0.1)	(0.1)	(0.1)			
Operating	1.3	1.3	1.3	1.2			
Development	1.8	1.7	1.5	1.4			
Severance tax/revenue	10.1%	10.1%	10.1%	10.1%			