APPENDIX A

This appendix provides additional sensitivity cases that show how various factors impact the value of the HBP option. It also presents a more disaggregated analysis of the value of leases in the five major U.S. shale gas basins.

Figure A1 shows how the value of the HBP option varies non-monotonically with the value of underlying natural gas reserves. When gas prices are low, the lease starts far out of the money with little chance that the operator would want to extend the primary term by drilling a sub-marginal well. When gas prices are high, the lease starts far in the money with little chance that the operator would want to delay exploitation.

Figure A2 Indicates how operations on an out-of-the money lease are impacted by the HBP provision. The figure is similar to Figure 2 of the main text, but with higher unit development cost, which is why the lease is out-of-the-money.

Figure A3 illustrates how the probability of exercising the HBP option develops as the primary term draws to a close.

Figure A4 plots the growth in shale gas production from the five major shale gas basins relative to the total shale gas production in the U.S.

Figure A5 shows the probability that the HBP option would either stimulate or suppress development in each sub-region and productivity tier of the five major U.S. shale gas basins.

Table A1 shows how the value of an out-of-the-money lease, and the associated HBP option, varies with lease term and the cost of development. It is similar to Table 1 of the main text but focuses on different determinants of value.

Table A2 shows how the value of the HBP option is affected by variations in lease term and well productivity. It is similar to Table 1 of the main text but focuses on different determinants of value.

Table A3 shows the distribution of shale gas development cost, by sub-area within each of the five main shale gas plays. These figures are calculated based on the well costs shown in Table 2 of the main text and the EIA distributions of well productivity shown in Table 3 of the main text.

Table A4 shows the ratio of lease values with and without the HBP provision in each sub-area and productivity tier of the five major shale gas basins. The values are derived from Equations 4 and 5 of the main text.

Table A5 shows the probability that the HBP option would either stimulate or suppress development in each sub-area and productivity tier of the five major shale gas basins. The calculations are performed as indicated in Figure 2 of the main text and Figure A2.

Figure A1: Value of the HBP Provision as a function of the Price of Developed Reserves

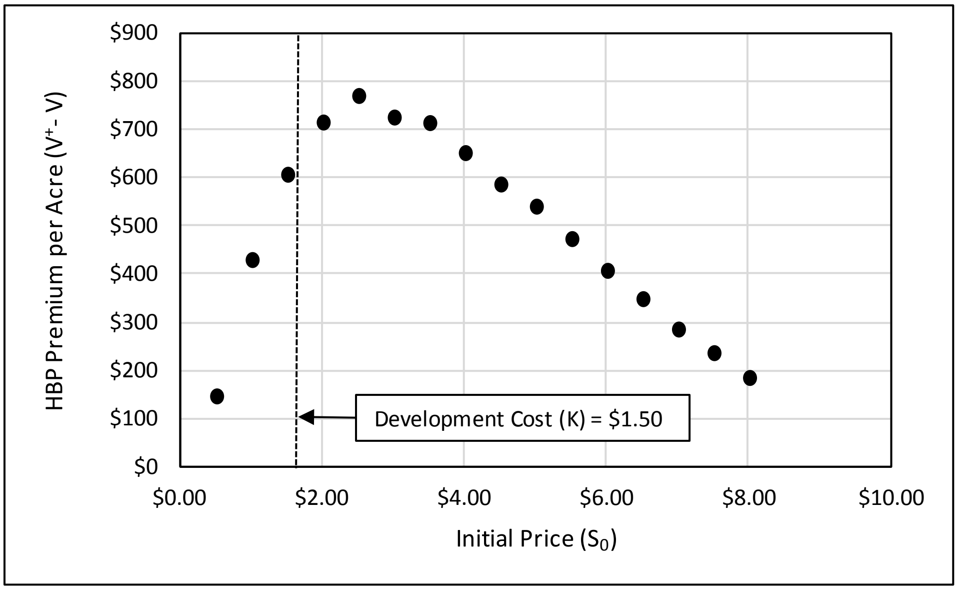

Figure A2: Optimal Development Timing: Out-of-the-Money Lease

The diagram depicts the full 25-step binomial price lattice used to value an undeveloped lease, including the optimal timing of investment. No investment should be made at nodes marked "O". Full development should be initiated at nodes marked "X". A single well should be drilled (to hold the lease by production) at nodes marked "D1". Without the HBP provision in the lease, all white cells switch to "X" and the shaded "D1" cells switch to "O". These switched cells show the impact of the HBP option on the scope and timing of investment. The lease in question is assumed to begin out-of-the-money at time t_o with *S= $1.00 and K* = $3.,00/MCF. Primary term is 3 years, *EUR* is 1 BCF per well, lease area is 640 acres with 80 acre spacing, which allows 8 wells. Volatility of reserve value is 50%; the real interest rate is 2%, and convenience yield is 1%.

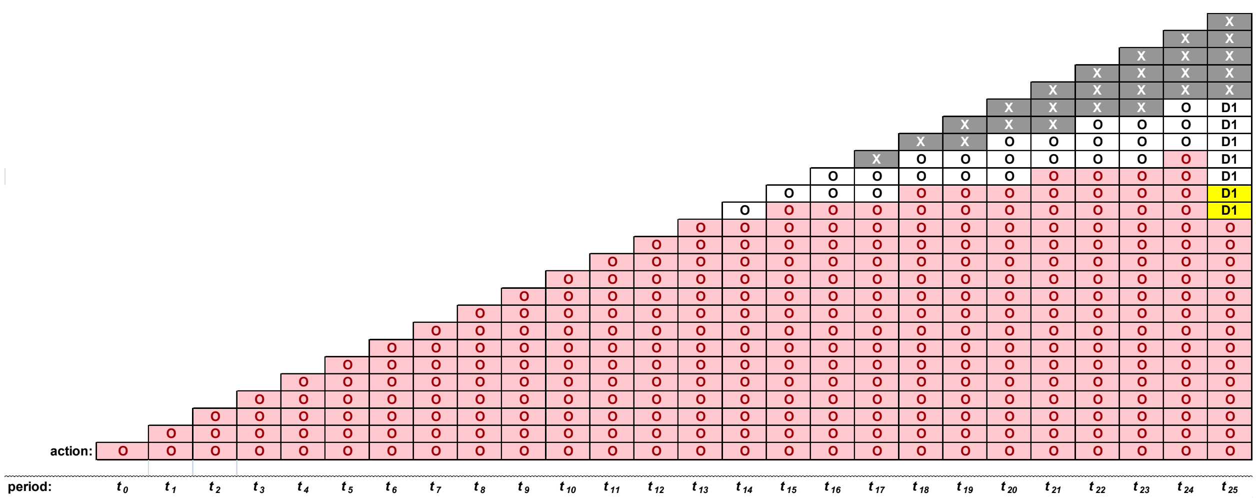

Figure A3: Probability of Exercising the HBP Option

The graph shows the conditional probability, at each point during the primary term of the lease, that the operator will drill a single well (as opposed to either drilling no well or initiating full development). The blue line is derived from the optimal investment decisions for the even-money lease shown in Figure 2 of the main text. The red line is derived from the optimal investment decisions for the out-of-the money lease shown in Figure A2 above. In both cases, the lease is 640 acres with 80 acre spacing, so 8 wells are required for full development. The primary term is for a period of 3 years, so each of the 24 time-steps represents the passage of 45 days.

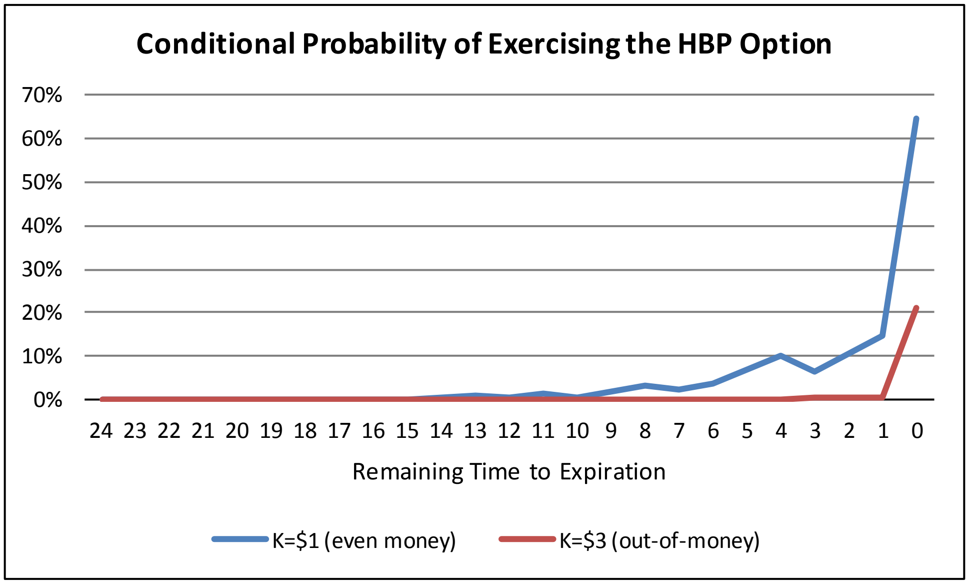

Figure A4: U.S. Shale Gas Production, by Basin

The chart shows total production of dry natural gas (natural gas liquids removed), by month, from each of the five main shale gas basins in the U.S. Shale gas production from the rest of the U.S. comes mainly from the Antrim, Bakken, Eagle Ford, and Utica basins. Source: U.S. Energy Information Administration.

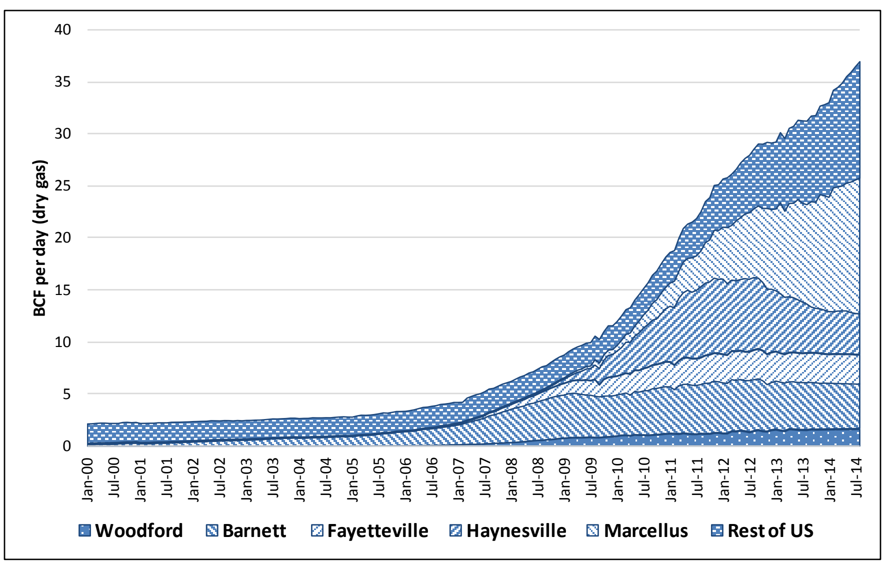

Figure A5: Probability the HBP Option Stimulates or Suppresses Development, by Sub-Area and Tier

For leases located in each productivity tier of each sub-area within each shale-gas basin, the figure shows the probability that the HBP option will be exercised during the last period of the primary term, thereby affecting the scope and timing of development. Blue bars represent the probability that the operator will drill a single well on the lease instead of undertaking full development. White bars show the probability the operator will drill a single sub-marginal well on the lease as opposed to letting it expire. Well spacing is as in Table 2 of the main text, *EUR* is as shown in Table 3 of the main text, and unit development cost is as shown in Table A3 above. In all cases the primary term is assumed to be three years, the value of reserves is $1/MCF, the volatility of reserve price is 50%, the real interest rate is 2%, and the convenience yield is 1%. Probabilities are calculated by the method illustrated in Figure 2 of the main text, using a 25-step lattice. Therefore, the probability of development impacts shown in these figures pertain to the final 45 days of the assumed three-year term. The probabilities shown here do not include the additional impact of earlier drilling deferrals, as indicated in Figure 2 of the main text and Figure A2 above.

Table A1: Value of Out-of-the-Money Leases with HBP Provision

The table shows how the value of a 640-acre natural gas lease with the HBP provision varies as a function of the primary term of the lease and unit development cost. A longer term increases the value of the lease because prices are assumed to follow Geometric Brownian Motion which creates increasing scope for high prices as time progresses. Higher development cost decreases the value of the lease because it reduces the chance of profitable development. The price of reserves is assumed to be S = \$1.00/MCF, with EUR = 1 BCF/well. It is also assumed that the volatility of the value of proved reserves is 50%, the real interest rate is 2%, and the convenience yield is 1%. The reported values are derived from Equation 5 of the main text.

Lease Value per Acre with HBP Option, and Relative to the Value Without HBP											
		Development Cost, K ($/MCF)									
		$0.50		$1.00		$1.50		$2.00		$3.00	
Primary Term (years)	1	$3,550	111%	$1,930	153%	$1,007	219%	$524	329%	$144	650%
	2	$3,670	109%	$2,255	128%	$1,435	155%	$942	182%	$439	225%
	3	$3,788	107%	$2,523	119%	$1,774	132%	$1,283	143%	$739	167%
	4	$3,898	106%	$2,751	114%	$2,053	122%	$1,564	130%	$998	143%
	5	$3,992	105%	$2,944	111%	$2,290	117%	$1,819	124%	$1,259	135%
	6	$4,081	104%	$3,111	109%	$2,498	114%	$2,050	119%	$1,505	125%

Table A2: Impact of Well Productivity on the Value of the HBP Provision

The table shows how the value of a 640-acre natural gas lease with the HBP provision varies as a function of the primary term of the lease and well productivity (EUR). A longer term increases the value of the lease because prices are assumed to follow Geometric Brownian Motion which creates increasing scope for high prices as time progresses. Greater well productivity increases the value of the lease, and also increases the absolute but not the relative value of the HBP provision. The price of reserves is assumed to be S = \$1.00/MCF, well cost is assumed to be C = \$6 million, with development cost given by $K = C/EUR$. Well spacing is 80 acres. It is also assumed that the volatility of the value of proved reserves is 50%, the real interest rate is 2%, and the convenience yield is 1%. The reported values are derived from Equation 5 of the main text.

Lease Value per Acre with HBP Option, and Relative to the Value Without HBP											
		Well Productivity, EUR (MCF) at 80 Acre Spacing, Well Cost = $6 million									
		500,000		1,000,000		2,000,000		3,000,000		4,000,000	
Primary Term (years)	1	$0	743905%	$23	6922%	$1,003	1134%	$4,381	459%	$9,973	271%
	2	$9	2104%	$221	673%	$2,260	289%	$6,749	217%	$12,995	175%
	3	$51	566%	$542	310%	$3,517	198%	$8,723	162%	$15,441	144%
	4	$118	306%	$895	236%	$4,608	165%	$10,353	143%	$17,466	130%
	5	$231	271%	$1,275	175%	$5,592	150%	$11,809	134%	$19,200	123%
	6	$343	189%	$1,692	164%	$6,494	135%	$13,103	126%	$20,744	118%

Table A3: Distribution of Development Cost, by Sub-Area, Within Each Basin

The table shows the probability distribution of unit development cost for wells located respectively in the best, average, and below-average areas of each major basin. For each sub-area of a basin, unit development cost is computed as 125% of well cost divided by the sub-area specific *EUR* per well. Well costs are as reported in Table 2 of the main text. *EUR* estimates are as reported in Table 3 of the main text. Well costs are inflated by 25% to allow for on-site costs in addition to drilling expenditures. Shaded cells indicate sub-areas within each basin that are under water when reserve price is $1/MCF.

Distributions of Development Cost, by Area	$/MCF				
	10%	20%	30%	40%	Average
Barnett					
a. Best Area	$0.73	$0.98	$1.46	$2.94	$1.88
b. Average Area	$0.97	$1.30	$1.95	$3.89	$2.50
c. Below Average Area	$1.30	$1.73	$2.60	$5.19	$3.33
Fayetteville					
a. Best Area	$0.35	$0.70	$1.06	$3.52	$1.90
b. Average Area	$0.47	$0.94	$1.41	$4.66	$2.52
c. Below Average Area	$0.63	$1.25	$1.88	$6.22	$3.36
Woodford-Arkoma					
a. Best Area	$0.53	$1.07	$1.60	$5.31	$2.87
b. Average Area	$0.71	$1.42	$2.13	$7.08	$3.83
c. Below Average Area	$0.95	$1.89	$2.83	$9.44	$5.10
Haynesville					
a. Best Area	$0.92	$1.22	$1.84	$3.68	$2.36
b. Average Area	$1.22	$1.63	$2.44	$4.89	$3.14
c. Below Average Area	$1.63	$2.17	$3.25	$6.51	$4.18
Marcellus					
a. Best Area	$0.35	$0.46	$0.69	$1.39	$0.89
b. Average Area	$0.46	$0.61	$0.92	$1.84	$1.18
c. Below Average Area	$0.61	$0.82	$1.23	$2.46	$1.58

Table A4: Ratio of Lease Values With and Without the HBP Provision, by Sub-Area and Tier

The table shows, for each productivity tier of each sub-area within each major shale-gas basin, the value of a three-year, 640-acre lease with the HBP provision relative to the value of a comparable lease that lacks the HBP provision. Well spacing is as in Table 2 of the main text, *EUR* as in Table 3 of the main text, and unit development cost as in Table A3 above. For all cases, we assume the value of reserves is $1/MCF, the volatility of reserve value is 50%, the real interest rate is 2%, and the convenience yield is 1%. The reported values are derived from Equations 4 and 5 of the main text.

Distributions of Ratio of Lease Value With HBP Provision to Lease Value Without HBP					
	$/MCF				
	10%	20%	30%	40%	Average
Barnett					
a. Best Area	114%	121%	134%	171%	144%
b. Average Area	121%	131%	148%	199%	162%
c. Below Average Area	131%	146%	168%	242%	190%
Fayetteville					
a. Best Area	104%	115%	128%	222%	161%
b. Average Area	108%	124%	140%	269%	185%
c. Below Average Area	113%	135%	158%	322%	215%
Woodford-Arkoma					
a. Best Area	108%	121%	136%	210%	160%
b. Average Area	112%	129%	147%	268%	188%
c. Below Average Area	118%	140%	160%	355%	230%
Haynesville					
a. Best Area	123%	135%	156%	225%	176%
b. Average Area	135%	150%	181%	278%	209%
c. Below Average Area	150%	168%	211%	342%	249%
Marcellus					
a. Best Area	104%	108%	115%	139%	122%
b. Average Area	108%	113%	123%	157%	133%
c. Below Average Area	113%	120%	135%	182%	149%

Table A5: Probability that HBP Option Stimulates or Suppresses Development, by Sub-Area and Tier

For leases located in each productivity tier of each sub-area within each major shale-gas basin, the table reports the probability that the HBP option will be exercised during the *last period* of the primary term, thereby affecting the scope and timing of development. Lines with "Drilling Impact" indicated by "-" show the probability that the operator will drill a single well on the lease instead of undertaking full development. Lines with "Drilling Impact" indicated by "+" show the probability the operator will drill a single sub-marginal well on the lease as opposed to letting the lease lapse. Well spacing is as in Table 2 of the main text, *EUR* is as in Table 3 of the main text, and unit development cost is as in Table A3 above. In all cases the primary term is assumed to be three years, the value of reserves is $1/MCF, the volatility of reserve price is 50%, the real interest rate is 2% and the convenience yield is 1%. Probabilities are calculated by the method illustrated in Figures 2 of the main text and A2 above, using a 25-step lattice. Therefore, the impacts shown in the table pertain to the final 45 days of the assumed three-year term. The probabilities shown here *do not include* the additional impact of earlier drilling deferrals, as indicated in Figures 2 and 2A.

Probabilities of Impacting Drilling During Last Period of Primary Term							
Basin		Drilling Impact	Top 10%	Next 20%	Next 30%	Bottom 40%	Average
Barnett	Best Area	-	47.7%	33.6%	20.9%	5.4%	20.9%
		+	15.6%	31.1%	13.2%	6.0%	13.2%
	Average Area	-	33.6%	20.9%	11.4%	2.2%	11.4%
		+	31.1%	28.7%	22.9%	9.3%	22.9%
	Below Average Area	-	20.9%	11.3%	5.4%	0.8%	5.4%
		+	28.7%	22.9%	15.7%	4.7%	15.7%
Fayetteville	Best Area	-	67.4%	47.7%	33.6%	2.2%	33.6%
		+	15.9%	29.0%	31.1%	9.3%	31.1%
	Average Area	-	60.0%	33.6%	20.9%	2.2%	20.9%
		+	23.2%	31.1%	28.7%	9.3%	28.7%
	Below Average Area	-	47.7%	20.4%	11.4%	0.8%	11.4%
		+	29.0%	28.7%	22.9%	4.7%	22.9%
Woodford	Best Area	-	60.0%	33.6%	20.9%	0.8%	20.9%
		+	13.4%	15.5%	13.2%	4.7%	13.2%
	Average Area	-	47.7%	20.9%	11.4%	0.2%	11.4%
		+	15.6%	13.2%	9.7%	2.0%	9.7%
	Below Average Area	-	33.6%	11.4%	5.4%	0.2%	5.4%
		+	31.1%	22.9%	6.0%	0.6%	6.0%
Haynesville	Best Area	-	33.6%	20.4%	11.4%	2.2%	11.4%
		+	31.1%	28.7%	22.9%	9.3%	22.9%
	Average Area	-	20.4%	20.9%	5.4%	0.8%	5.4%
		+	28.7%	28.7%	15.7%	4.7%	15.7%
	Below Average Area	-	20.9%	11.4%	5.4%	0.8%	5.4%
		+	28.7%	22.9%	15.7%	4.7%	15.7%
Marcellus	Best Area	-	67.4%	60.0%	47.7%	20.9%	47.7%
		+	15.9%	23.2%	29.0%	28.7%	29.0%
	Average Area	-	60.0%	44.4%	33.6%	11.4%	33.6%
		+	23.2%	29.0%	31.1%	22.9%	31.1%
	Below Average Area	-	44.4%	47.7%	20.4%	5.4%	20.4%
		+	29.0%	29.0%	28.7%	15.7%	28.7%