in a European option), forfeitures, underperformance, stock price barriers, vesting periods, changing business environments and volatilities, suboptimal early exercise behavior, and a slew of other conditions. Monte Carlo simulation when used alone is another option valuation approach, but is restricted only to European options. Simulation can be used in two different ways: to solve the option's fair-market value through path simulations of stock prices, or used in conjunction with other approaches (e.g., binomial lattices and closed-form models) to capture multiple sources of uncertainty in the model.

Binomial lattices are flexible and easy to implement. They are capable of valuing American-type stock options with dividends but require computational power. Software applications should be used to facilitate this computation. Binomial lattices can be used to calculate American options paying dividends and can be easily adapted to solve ESOs with exotic inputs and used in conjunction with Monte Carlo simulation to account for the uncertain input assumptions (e.g., probabilities of forfeiture, suboptimal exercise behavior, vesting, underperformance) and to obtain a high precision at statistically valid confidence intervals. Based on the analyses throughout the case study, it is recommended that the use of a model that assumes an ESO is European style when, in fact, the option is American style with the other exotic variables should not be permitted, as this substantially overstates compensation expense. Many factors influence the fair-market value of ESOs, and a binomial lattice approach to valuation that considers these factors should be used. With due diligence, real-life ESOs can absolutely be valued using the customized binomial lattice approach as shown in this case study, where the methodology employed is pragmatic, accurate, and theoretically sound.

CASE STUDY: OIL AND GAS ROYALTY LEASE NEGOTIATION

This case was contributed by David Mercier, vice president of corporate development at Bonanza Creek Energy. Mr. Mercier has executive experience in starting, financing, and selling businesses. As the chief of finance, economics, and accounting for the California State Lands Commission Mineral Resources Division, he was responsible for maximizing the value of more than 20,000 barrels of oil per day. His responsibilities included profit-sharing negotiations, crude oil and natural gas marketing, royalty accounting, financial review of lease assignments, financial risk management, and revenue forecasting and budgeting. In short, with more than 20 years of experience, Mr. Mercier has worked in every aspect of the energy business.

He has published and presented numerous technical papers and has written case studies for risk modeling text books. He has presented many papers throughout the United States on maximizing value using a royalty rate that slides with oil price. California was the first state to employ this type of royalty. He is a member of the Society of Petroleum Engineers and was a California Natural Gas Committee member. Prior to joining the State Lands Commission, Mr. Mercier worked as an environmental consultant for TRC, a process engineer for Mobil Oil Company, and a commodity trader. He is an active member of and donor to the Autism Society of America. He holds a B.S. degree in petroleum engineering, University of Southern California (USC), an M.B.A. degree (finance), is Certified in Risk Management (CRM), and completed the SDRM (Strategic Decision and Risk Management) program at Stanford University.

Background

Since 1938, the California State Lands Commission (SLC, or "Commission") has had exclusive jurisdiction over the leasing of oil and gas from offshore state lands. In March 2005, Plains Exploration & Production Company (PXP) applied to the California State Lands Commission and County of Santa Barbara for a new state lease and onshore permits to allow development of the Tranquillon Ridge field, located in state waters offshore from Vandenberg Air Force Base. PXP plans to use an existing platform, Platform Irene, which is currently used to produce oil and gas from the adjacent Pt. Pedernales field, in federal waters (Figure 14.58). Like the oil produced from Pt. Pedernales, oil produced from Tranquillon Ridge would be sent to shore by pipeline and processed at the Lompoc Oil and Gas Plant (LOGP); therefore, no new construction. However, the project requires a new state lease

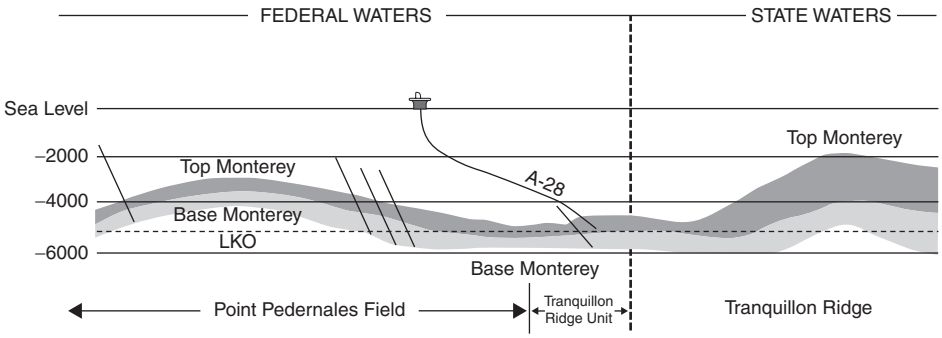


FIGURE 14.58 Picture of the development.

to allow "extended reach drilling" from Platform Irene into the Tranquillon Ridge field.

The lease could be issued under an exception to the California Coastal Sanctuary Act (1984), which allows a new lease if oil or gas from state-owned tide and submerged lands "are being drained by means of producing wells upon adjacent federal lands and the lease is in the best interests of the state" (Pub. Res. Code §6244.). In this case, PXP is draining oil and gas from state tide and submerged lands from wells drilled on Platform Irene. The parties to the Settlement Agreement believe the provisions that have been negotiated are in the best interests of the state, not only because they provide specific environmental benefits, but also because they set a new precedent for full mitigation of the impact of industrial development in the county and the state.

The Agreement

A previous proposal to develop the Tranquillon Ridge Field, by Nuevo Energy Company, was opposed by local environmental groups and denied by the County of Santa Barbara in 2002. When PXP made a similar proposal, the environmental groups again raised objections, based on the fact that the drilling operations would extend the life of the existing facilities. PXP responded by agreeing to include a termination date for the Tranquillon Ridge Project. This commitment goes well beyond any legal requirements, which allow oil companies to continue operations so long as they are producing commercially viable quantities of oil and gas.

The Environmental Defense Center (EDC), Get Oil Out! (GOO!), and Citizens Planning Association of Santa Barbara (CPA) signed an historic and unprecedented agreement in Santa Barbara, California. The agreement allowed for development by PXP of the Tranquillon Ridge Oil and Gas Field offshore Lompoc, while curtailing the life of existing oil and gas operations.

In addition to the royalty schedule, PXP agreed to the following:

- The Tranquillon Ridge Project will include an "end date" that will prohibit any extension of the life of existing oil and gas operations.
- PXP will phase out other oil and gas production operations in the county, both offshore near Pt. Arguello and Pt. Conception and onshore near Lompoc.
- All greenhouse gas emissions from the Tranquillon Ridge Project will be mitigated or offset, resulting in carbon neutrality.
- PXP will donate an additional $1,500,000 to reduce greenhouse gas emissions in the county.

- PXP will convey approximately 3,900 acres of land, including approximately 3,700 acres adjacent to the Burton Mesa Ecological Reserve in the Lompoc Valley and up to 200 acres on the Gaviota Coast, for the benefit of the public.

The Negotiated Royalty Rate Schedule

The California State Lands Commission (CSLC) finance and economics chief, David Mercier, together with Dr. Johnathan Mun ("Consultant"), designed, evaluated, and negotiated the royalty schedule illustrated in Figure 14.59 with PXP.

Why Use a Priced-Based Sliding Scale Royalty?

In the United States, oil and gas property owners typically charge the producer a royalty rate, with the most common being 16.7 percent of the gross revenue. The initial analysis illustrated the benefits of using an oil price-based sliding scale royalty: The royalty rate is low when the price is low and vice versa. This type of royalty schedule can benefit both the royalty owner and operator by encouraging operator investment, mitigating royalty-induced production drops, and lowering the likelihood of abandonment. Increasing

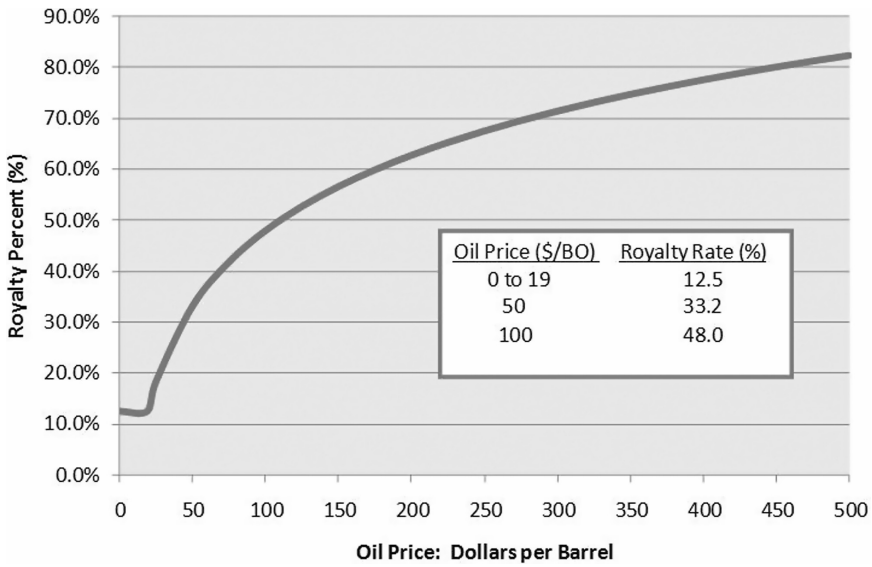


FIGURE 14.59 State royalty rate versus oil price.

the amount of investment in development projects will likely increase the production rate, field value, and royalty revenue

$$(Royalty\ Revenue = Oil\ Price * Production\ Rate * Rate\ Rate)$$

Traditionally, many royalty owners have tried to get the highest fixed royalty rate possible, thinking that a higher rate naturally translates into more royalty revenue. This approach has resulted in royalties that need to be renegotiated when the oil price goes lower than predicted to prevent premature abandonment. Negotiating the highest possible royalty rate the producer will accept should never be the royalty owner's strategy. High royalty rates do not necessarily maximize royalty revenue.

In any profit-sharing agreement the (royalty owner–operator) economic interdependence is large; these negotiations should not be treated as a zero-sum game (like chess) where someone wins and the other loses. When the royalty rate is high and the oil price is low, a royalty owner–operator win-lose relationship usually ends up lose-lose in the long term. The only way the royalty owner can win in the long term is to make sure the royalty rate is low when the price is low and vice versa. This arrangement ensures that the royalty rate is not so high at low oil prices that it triggers premature field abandonment or royalty-induced production drops (lose-lose).

To better understand how the royalty rate affects an operation, it is important to note that an X percent royalty rate has the same effect on an operator's shut-in, drilling, and well-work decisions as an X percent reduction in oil price or an X percent increase in operating costs.

Net profits sharing contracts are progressive systems employed in many places around the world; however, typically, these contracts require the mineral owner to be constantly evaluating the details of the operation. For many operations this additional accounting expense is cost-prohibitive. This continuous auditing of the operation to ensure proper payment can be costly for both the mineral owner and operator. Accounting disputes can often lead to expensive litigation and a serious deterioration of the mineral owner–operator relationship. Huge amounts of value can be lost (for both parties) if the operation's human and financial resources shift focus from optimizing the value of the field to expensive litigation/arbitration. Also, net profit contracts, as compared with royalty contracts, may expose the mineral owner to increased financial liability—the risk of negative cash flow or negative balance. Increased financial risk is not bad when it comes with a proportionate amount of increased benefit. However, because of the strong correlation between operator profits and oil price, a royalty schedule that tracks oil price can provide the same or better (if designed properly) revenue stream without all the administrative costs associated with the typical net-profits types of agreements.

Royalty Design Strategy

The royalty schedule (Figure 14.59) is the result of thousands of scenario combinations and permutations of royalty rates and PXP's IRR as well as other metrics. This royalty schedule was developed to maximize the total NPV of the project, and to the state. At the same time, the constraint is that PXP needs to be profitable given these royalty rates. At royalty rates that are too high, PXP will find the project unprofitable and not proceed with development.

Analysis Steps and Modeling

Building the Decision Model The first step to develop the optimal royalty schedule was building the financial model in Excel. Before building the model, some time was taken to plan the model's structure. A decision diagram provided a high-level blueprint of the model's structure. The decision diagram emphasizes which inputs are used to calculate the results and how the uncertain inputs may be interdependent on each other.

The model flow is sequential, first identifying the input variables (oil price, expense, etc.), then setting up the calculations, and then providing the summary output metrics.

Evaluating the Tornado Diagram After the model was built, a tornado diagram was generated. This is actually a great debugging tool because it varies all of the inputs. The example tornado summary shown in Figure 14.60 details how each input variable affected the state's and PXP's NPV, and which inputs were the most important.

Not surprisingly, the main critical success factors in this project are:

- Oil price
- Royalty rates
- Volume/production risk
- Discount or hurdle rate

Distributional Analysis After identifying which input variables affect the state's and PXP's NPV, the oil price history uncertainty was captured into the model using distributional analysis.

Preliminary Analysis: GARCH Volatility Estimates After understanding the key impact drivers in the model, the focus was on calibrating these variables. Thousands of simulation trials and scenarios were run on these key impact drivers to determine the outcome of the project. In other words,

Tornado Summary

CSLC	Base Value: 2766.89539618279			Input Changes		
Precedent Cell	Output Downside	Output Upside	Effective Range	Input Downside	Input Upside	Base Case Value
Royalty Function (H7)	$ 2,199	$ 3,335	$ 1,137	0.19	0.24	0.21
Oil Price	$ 2,373	$ 3,173	$ 800	90.00	110.00	100.00
Royalty Function (H6)	$ 3,059	$ 2,475	$ 583	0.46	0.56	0.51
Volume Risking	$ 2,490	$ 3,044	$ 553	0.90	1.10	1.00
SLC Discount Rate	$ 2,919	$ 2,625	$ 294	7.2%	8.8%	8.0%
			$ 3,367			

PXP	Base Value: 1786.5447300599			Input Changes		
Precedent Cell	Output Downside	Output Upside	Effective Range	Input Downside	Input Upside	Base Case Value
Royalty Function (H7)	$ 2,262	$ 1,311	$ 952	0.19	0.24	0.21
Royalty Function (H6)	$ 1,542	$ 2,031	$ 488	0.46	0.56	0.51
Volume Risking	$ 1,550	$ 2,023	$ 473	0.90	1.10	1.00
Oil Price	$ 1,648	$ 1,915	$ 267	$ 90	$ 110	$ 100
PXP Discount Rate	$ 1,911	$ 1,673	$ 238	9.7%	11.8%	10.8%
			$ 2,418			

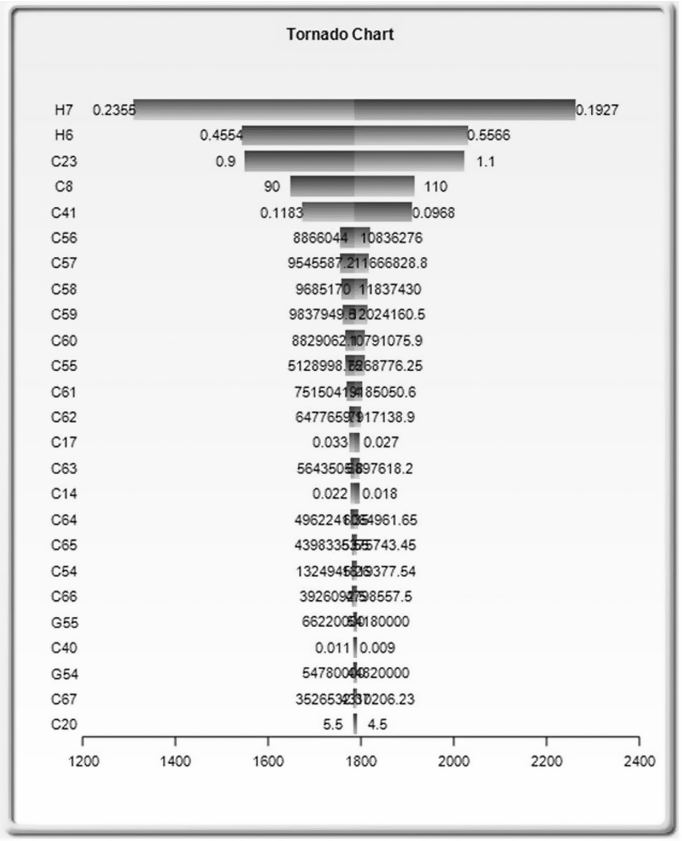


FIGURE 14.60 Tornado summary and chart.

Single Variable Distributional Fitting

Statistical Summary

Fitted Distribution	***Gumbel (Maximum)***	
Alpha	*67.06*	
Beta	*12.70*	
Kolmogorov-Smirnov Statistic	*0.07*	
P-Value for Test Statistic	*0.1102*	
	Actual	*Theoretical*
Mean	*74.45*	*74.39*
Standard Deviation	*13.00*	*16.29*
Skewness	*0.36*	*1.14*
Excess Kurtosis	*-1.16*	*2.40*

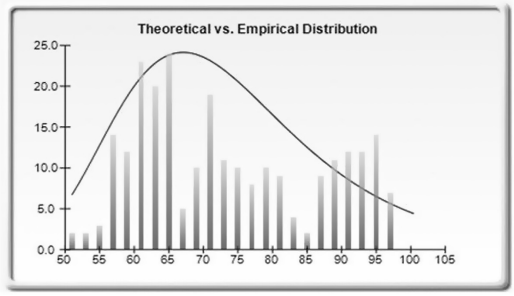


FIGURE 14.61 Historical oil price distribution.

less attention was paid to those variables that have little impact on the outcome of the project. After all, why spend too much time calibrating the inputs to the variables that have negligible effects on the NPV of the project (e.g., the variables at the bottom of the tornado chart)?

As oil price is the major impact driver, our next step was to determine the risk and volatility of this variable by looking at historical oil prices (Figure 14.61). Figure 14.62 shows the results from a GARCH (generalized autoregressive conditional heteroskedasticity) model that was run to forecast the volatility of the price of oil using historical price levels. Figure 14.63 shows some sample oil price data coupled with macroeconomic variables such as gross domestic product and variables such as inflation and interest rates. These were entered into some advanced econometric models in order to forecast the levels of oil prices and its uncertainties (Figure 14.64 shows some sample results from ARIMA, or autoregressive integrated moving average, models). The results from these analyses were then used to recalibrate the cash flow models, where tens of thousands of simulation trials were run to determine the returns and risks of the project both to the state and PXP.

Risk Analysis (Monte Carlo Risk-Based Simulation) To properly determine the risks and uncertainties involved in the project, we employed Monte Carlo risk simulation and ran 1,000 to 100,000 simulation trials on the financial and economic models to account for all possible outcomes. The variables we simulated were those found to be the most sensitive in driving the NPV and IRR of the project. These critical success factors (e.g., price of oil and oil production) were difficult to forecast with any certainty, hence we employed simulation techniques to handle these uncertainties.

GARCH: Generalized Autoregressive Conditional Heteroskedasticity (Volatility Forecast)

GARCH models are used mainly for computing the volatility on liquid and tradable assets such as stocks in financial options; this model is sometimes used for other traded assets such as price of oil and price of electricity. The drawback is that a lot of data is required, advanced econometric modeling expertise is required, and this approach is highly susceptible to user manipulation. The benefit is that rigorous statistical analysis is performed to find the best-fitting volatility curve, providing different volatility estimates over time. GARCH is a term that incorporates a family of models that can take on a variety of forms, known as GARCH (P,Q), where P and Q are positive integers that define the resulting GARCH model and its forecasts. In most cases for financial instruments, a GARCH

GARCH Model (P, Q)	1,1	Periodicity (Periods/Year)	12
Optimized Alpha	0.3243	Predictive Base	1
Optimized Beta	0.5756	Forecast Periods	3
Optimized Omega	0.0009	Variance Targeting	FALSE

Real Options Valuation
www.realoptionsvaluation.com

Period	Data	Volatility
0	59.40	
1	58.26	
2	59.45	23.43%
3	60.47	20.83%
4	60.91	19.06%
5	59.44	17.70%
6	57.73	17.47%
7	56.76	17.64%
8	55.36	17.10%
9	55.92	17.17%
10	56.45	16.60%
11	57.59	16.26%
12	57.07	16.43%
13	56.39	16.15%
14	55.34	16.06%
15	53.00	16.26%
16	53.57	18.08%
17	53.40	17.17%
18	52.10	16.50%
19	50.85	16.81%
20	48.77	16.96%
21	46.21	18.32%
22	48.73	20.22%
23	50.39	21.14%
24	51.26	20.08%
25	48.74	18.59%
26	47.83	20.00%
27	47.84	18.60%
28	48.31	17.36%

GARCH or generalized autoregressive conditional heteroskedasticity models are used in forecasting the volatility of financial instruments, using the prices themselves. The GARCH (P,Q) model allows for different positive P and Q integer lag parameters for the mean (news) and variance equations. Note than only positive data values can be used in a GARCH volatility forecast. Periodicity is the number of periods per year (e.g., 12 for monthly data, 252 for daily trading data, 365 for daily data) to annualize the volatility or keep as 1 for periodic volatility. Base is the predictive base periods (this means how many periods back you would like to use as a forecast base to predict future volatility, and is typically between 1 and 12). Variance Targeting means if you wish the volatility forecast to revert to an imputed long-run mean over time. Make sure to arrange your raw price data in chronological order (past to present in a single

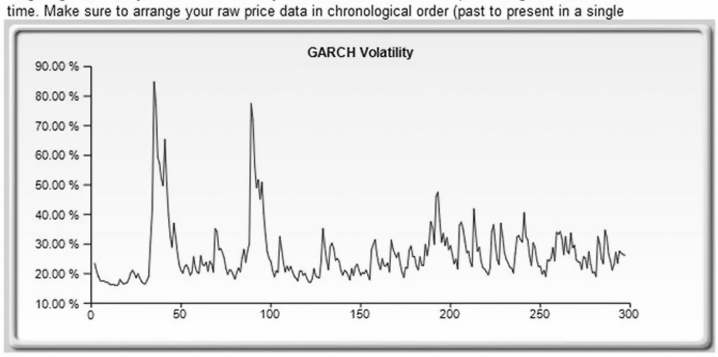


FIGURE 14.62 Generalized autoregressive conditional heteroskedasticity (volatility forecast).

Figures 14.65 through 14.71 illustrate a small sample set of the analysis performed, and the descriptions of our findings are listed here:

- Figure 14.65 shows simulation forecast results that indicate the state's NPV levels and NPV share of the total NPV of the project, assuming that the best-case scenario occurs. The 90 percent confidence interval means that 90 percent of the time, given all that can occur in terms of price of oil and actual production as well as other uncertainties (assuming that production is at full capacity), the state will yield an NPV of between \$1.21B and \$4.59B, which is equivalent to obtaining between 55.51 percent and 68.70 percent of the total NPV. This result

	A	B	C	D	E	F	G	H	I
1	Date	U.S. Natural Gas Wellhead Price (Dollars per Thousand Cubic Feet)		Date	Cushing, OK Crude Oil Future Contract 1 (Dollars per Barrel)	CPI	Adjusted Contract Crude Oil Price	Adjusted Natural Gas Wellhead Price	PXP Contract Crude Oil Price
392	Jul-2005	6.71		Jul-2005	59.03	201.4		7.31	55.94
393	Aug-2005	6.48		Aug-2005	64.99	203.1		7.00	61.07
394	Sep-2005	8.95		Sep-2005	65.55	205.8		9.54	60.79
395	Oct-2005	10.33		Oct-2005	62.27	206.9		10.95	57.44
396	Nov-2005	9.89		Nov-2005	58.34	205.6		10.55	54.16
397	Dec-2005	9.08		Dec-2005	59.45	203.9		9.77	55.65
398	Jan-2006	8.02		Jan-2006	65.54	206		8.54	60.72
399	Feb-2006	6.86		Feb-2006	61.93	207.5		7.25	56.96
400	Mar-2006	6.44		Mar-2006	62.97	208.5		6.78	57.64
401	Apr-2006	6.38		Apr-2006	70.16	210.5		6.65	63.61
402	May-2006	6.24		May-2006	70.96	212.4		6.44	63.76
403	Jun-2006	5.78		Jun-2006	70.97	211.1		6.01	64.16
404	Jul-2006	5.92		Jul-2006	74.46	211.4		6.14	67.22
405	Aug-2006	6.56		Aug-2006	73.08	211.9		6.79	65.82
406	Sep-2006	6.06		Sep-2006	63.9	212.9		6.24	57.28
407	Oct-2006	5.09		Oct-2006	59.14	211.4		5.28	53.39
408	Nov-2006	6.72		Nov-2006	59.4	211.1		6.98	53.70
409	Dec-2006	6.76		Dec-2006	62.09	210.6		7.04	56.27
410	Jan-2007	5.92		Jan-2007	54.35	212.584		6.11	48.79
411	Feb-2007	6.66		Feb-2007	59.39	214.76		6.80	52.78
412	Mar-2007	6.56		Mar-2007	60.74	216.5		6.65	53.55
413	Apr-2007	6.84		Apr-2007	64.04	217.845		6.89	56.11
414	May-2007	6.98		May-2007	63.53	218.596		7.00	55.47
415	Jun-2007	6.86		Jun-2007	67.53	217.273		6.93	59.32
416	Jul-2007	6.19		Jul-2007	74.15	217.454		6.24	65.08
417	Aug-2007	5.9		Aug-2007	72.36	217.33		5.96	63.54
418	Sep-2007	5.61		Sep-2007	79.63	217.697		5.65	69.81
419	Oct-2007	6.25		Oct-2007	85.66	218.696		6.27	74.75
420				Nov-2007	94.63	219.943			82.11
421				Dec-2007	91.74	219.373			79.81

FIGURE 14.63 Oil price forecasts using macroeconomic factors.

also means that in the 5 percent worst-case scenario, if production is at full capacity, the state will yield at least $1.21B (55.51 percent NPV share). This amount increases the possibility that the state will not get any more than $4.59B (68.70 percent NPV share) 5 percent of the time (that the state will only be able to beat these values at the absolute best-case scenario will occur less than 5 percent of the time).

- Figure 14.66 shows the same analysis as done for Figure 14.65 with the average NPV at $2.80B, or 62.74 percent NPV share if the production is at full capacity.

AUTO-ARIMA (Autoregressive Integrated Moving Average)

Regression Statistics

R-Squared (Coefficient of Determination)	0.9633	Akaike Information Criterion (AIC)	4.7115
Adjusted R-Squared	0.9630	Schwarz Criterion (SC)	4.7695
Multiple R (Multiple Correlation Coefficient)	0.9815	Log Likelihood	-692.59
Standard Error of the Estimates (SEy)	13.33	Durbin-Watson (DW) Statistic	2.0070
Number of Observations	294	Number of Iterations	6

Autoregressive Integrated Moving Average or ARIMA(p,d,q) models are the extension of the AR model that use three components for modeling the serial correlation in the time-series data. The first component is the autoregressive (AR) term. The AR(p) model uses the p lags of the time series in the equation. An AR(p) model has the form: y(t)=a(1)*y(t-1)+...+a(p)*y(t-p)+e(t).The second component is the integration (d) order term. Each integration order corresponds to differencing the time series. I(1) means differencing the data once. I(d) means differencing the data d times. The third component is the moving average (MA) term. The MA(q) model uses the q lags of the forecast errors to improve the forecast. An MA(q) model has the form: y(t)=e(t)+b(1)*e(t-1)+...+b(q)*e(t-q).Finally, an ARMA(p,q) model has the combined form: y(t)=a(1)*y(t-1)+...+a(p)*y(t-p)+e(t)+b(1)*e(t-1)+...+b(q)*e(t-q).

The R-Squared, or Coefficient of Determination, indicates the percent variation in the dependent variable that can be explained and accounted for by the independent variables in this regression analysis. However, in a multiple regression, the Adjusted R-Squared takes into account the existence of additional independent variables or regressors and adjusts this R-Squared value to a more accurate view the regression's explanatory power. However, under some ARIMA modeling circumstances (e.g., with nonconvergence models), the R-Squared tends to be unreliable.

The Multiple Correlation Coefficient (Multiple R) measures the correlation between the actual dependent variable (Y) and the estimated or fitted (Y) based on the regression equation. This correlation is also the square root of the Coefficient of Determination (R-Squared).

The Standard Error of the Estimates (SEy) describes the dispersion of data points above and below the regression line or plane. This value is used as part of the calculation to obtain the confidence interval of the estimates later.

The AIC and SC are often used in model selection. SC imposes a greater penalty for additional coefficients. Generally, the user should select a model with the lowest value of the AIC and SC.

The Durbin-Watson statistic measures the serial correlation in the residuals. Generally, DW less than 2 implies positive serial correlation.

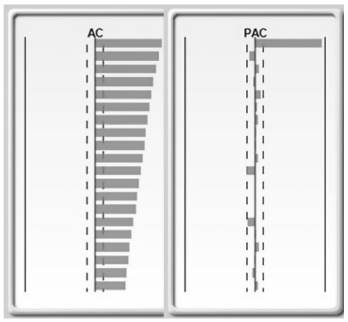
Regression Results

	Intercept	AR(1)	MA(1)
Coefficients	0.7421	0.9796	0.2874
Standard Error	0.5320	0.0147	0.0571
t-Statistic	1.3950	66.6201	5.0313
p-Value	0.1641	**0.0000**	**0.0000**
Lower 5%	1.6199	1.0038	0.3816
Upper 95%	-0.1357	0.9553	0.1931

Degrees of Freedom		Hypothesis Test	
Degrees of Freedom for Regression	2	Critical t-Statistic (99% confidence with df of 291)	2.5928
Degrees of Freedom for Residual	291	Critical t-Statistic (95% confidence with df of 291)	1.9681
Total Degrees of Freedom	293	Critical t-Statistic (90% confidence with df of 291)	1.6501

Autocorrelation

Time Lag	AC	PAC	Lower Bound	pper Bound	Q-Stat	Prob
1	0.9583	0.9583	(0.1164)	0.1164	272.7748	-
2	0.9117	(0.0826)	(0.1164)	0.1164	520.4740	-
3	0.8706	0.0489	(0.1164)	0.1164	747.1625	-
4	0.8296	(0.0316)	(0.1164)	0.1164	953.6689	-
5	0.7966	0.0841	(0.1164)	0.1164	1,144.7658	-
6	0.7690	0.0325	(0.1164)	0.1164	1,323.4421	-
7	0.7453	0.0404	(0.1164)	0.1164	1,491.8665	-
8	0.7234	0.0081	(0.1164)	0.1164	1,651.1049	-
9	0.7029	0.0171	(0.1164)	0.1164	1,801.9631	-
10	0.6859	0.0422	(0.1164)	0.1164	1,946.1286	-
11	0.6590	(0.1255)	(0.1164)	0.1164	2,079.6593	-
12	0.6307	0.0003	(0.1164)	0.1164	2,202.4156	-
13	0.6051	0.0067	(0.1164)	0.1164	2,315.7966	-
14	0.5800	0.0049	(0.1164)	0.1164	2,420.3514	-
15	0.5484	(0.1111)	(0.1164)	0.1164	2,514.1731	-
16	0.5187	0.0099	(0.1164)	0.1164	2,598.3934	-
17	0.4962	0.0544	(0.1164)	0.1164	2,675.7356	-
18	0.4737	(0.0197)	(0.1164)	0.1164	2,746.4771	-
19	0.4500	(0.0362)	(0.1164)	0.1164	2,810.5473	-
20	0.4316	0.0379	(0.1164)	0.1164	2,869.6993	-



Forecasting

Period	Actual (Y)	Forecast (F)	Error (E)
2	58.2609	58.9272	(0.6664)
3	59.4452	57.6212	1.8240
4	60.4724	59.4971	0.9753
5	60.9053	60.2593	0.6460
6	59.4446	60.5888	(1.1442)
7	57.7311	58.6435	(0.9124)
8	56.7621	57.0316	(0.2695)
9	55.3630	56.2671	(0.9042)
10	55.9174	54.7142	1.2032
11	56.4486	55.8629	0.5857
12	57.5938	56.2058	1.3880
13	57.0702	57.5582	(0.4880)
14	56.3888	56.5061	(0.1173)
15	55.3367	55.9452	(0.6085)
16	52.9967	54.7735	(1.7768)
17	53.5671	52.1455	1.4216
18	53.4029	53.6234	(0.2205)
19	52.1006	52.9906	(0.8901)
20	50.8523	51.5225	(0.6702)
21	48.7739	50.3629	(1.5890)
22	46.2088	48.0630	(1.8542)

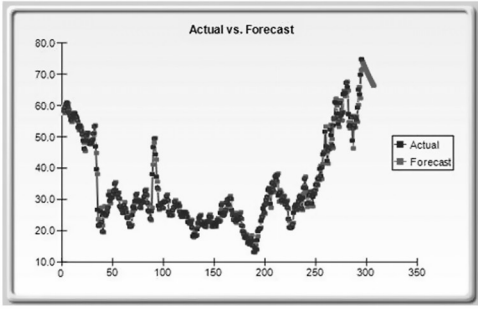


FIGURE 14.64 Oil price forecasts using advanced econometric ARIMA models.

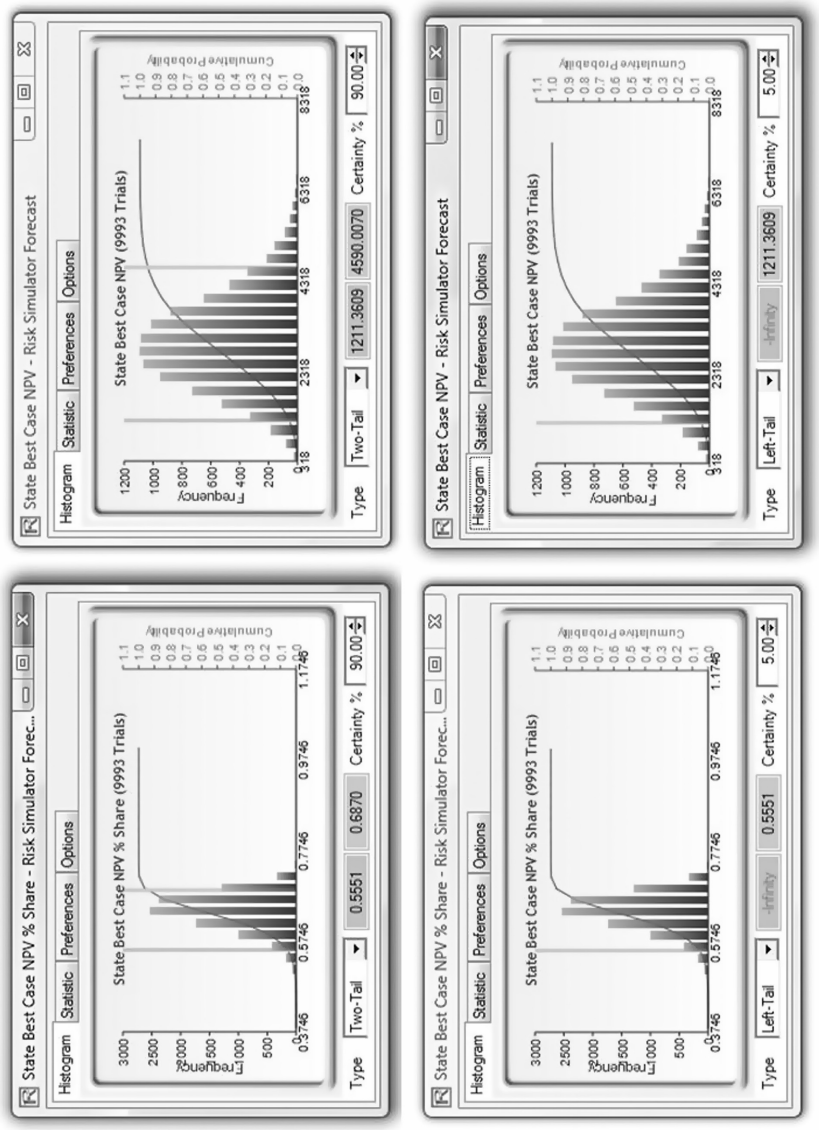


FIGURE 14.65 A sample of state's risk profile I (simulation results).

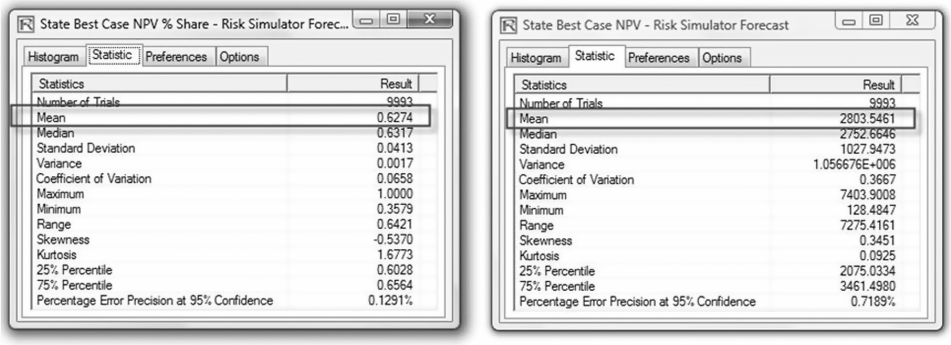


FIGURE 14.66 A sample of state's risk profile II (simulation results).

- Figure 14.67 shows the results of the analysis when the level of production is at the most likely middle-case scenario, where the state will be receiving an expected average of $744M and between 68.67 percent and 87.07 percent of the NPV share. The worse the situation, the higher the percentage NPV share the state receives because it carries no risk whereas PXP takes all the risk (although both the state and PXP will have reduced NPV dollar values).
- Figure 14.68 illustrates the results for PXP. In the best-case and most likely mid-case, the NPV on a 90 percent confidence interval shows that PXP will always have a significant NPV. The only way PXP will not obtain positive NPV values is when production is super low and close to a standstill, under the worst-case scenario.
- Figure 14.69 illustrates PXP's probability of success in generating a positive NPV for the entire project, at the sliding royalty rate proposed

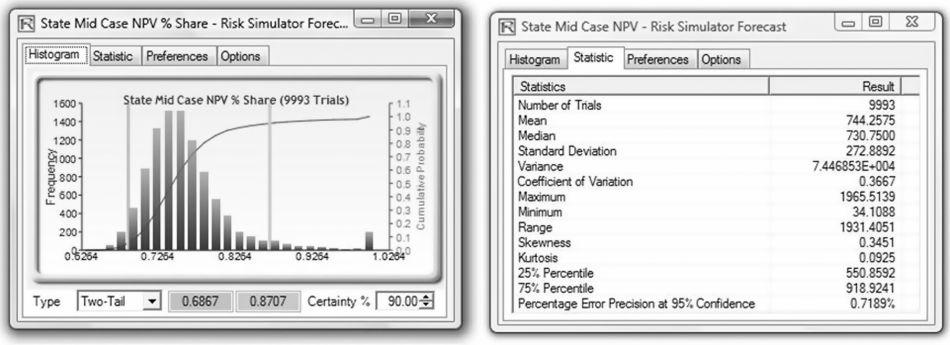


FIGURE 14.67 A sample of state's risk profile III (simulation results).

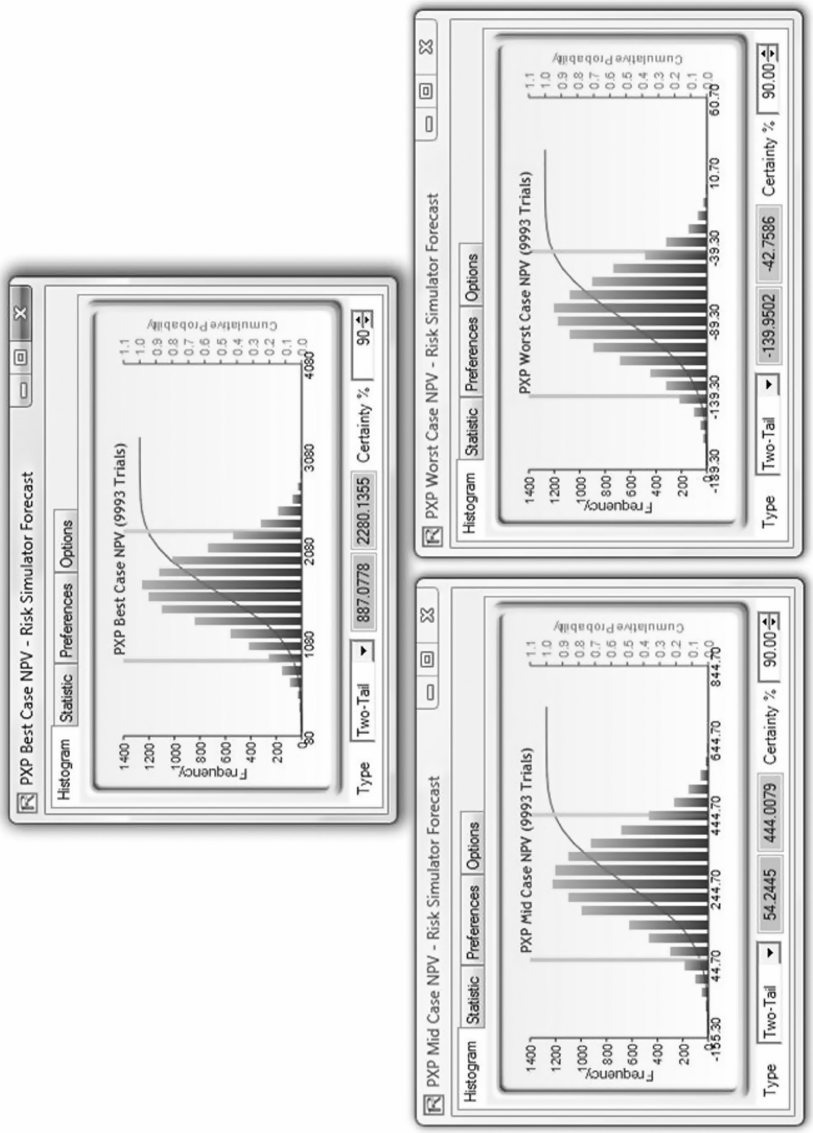


FIGURE 14.68 A sample of PXP's risk profile I (simulation results).

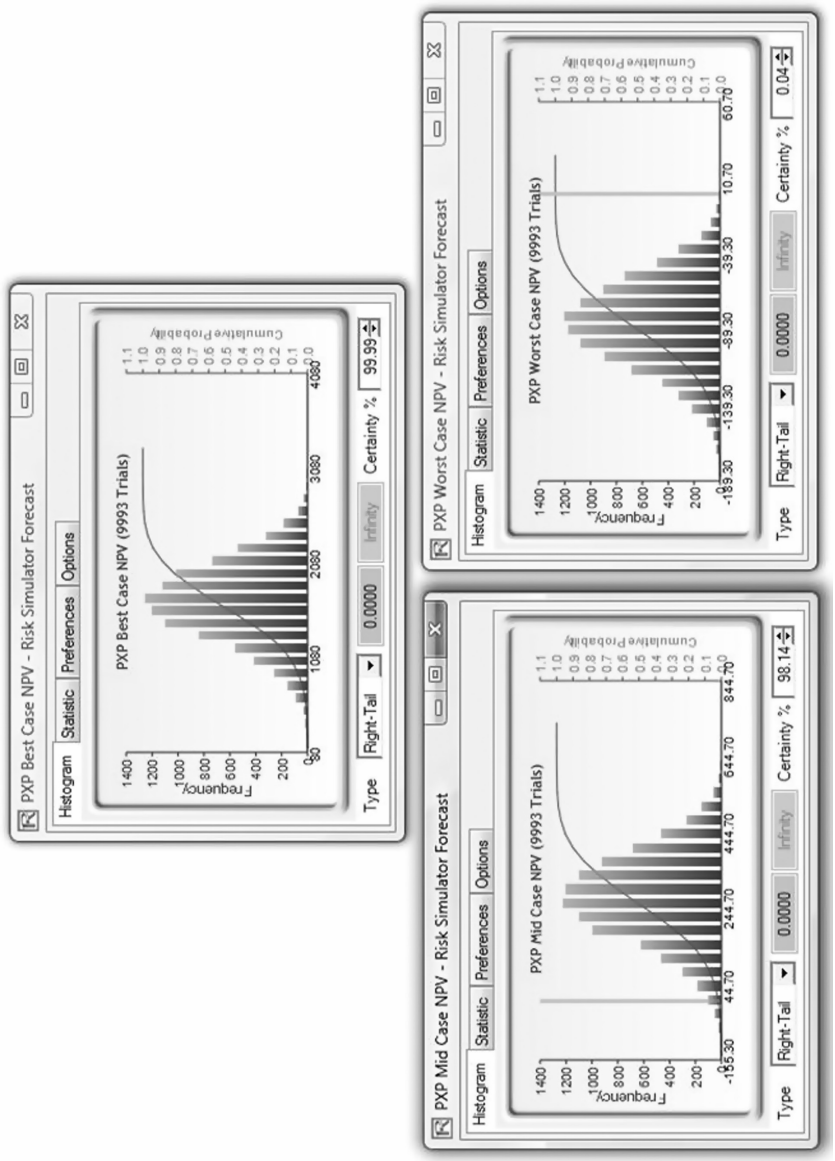


FIGURE 14.69 A sample of PXP's risk profile II (simulation results).

by the state. There is a 99.99 percent and 98.14 percent chance that NPV will be positive in the best- and most likely mid-case scenarios for PXP. This result indicates that there is less than a 2 percent chance that the project will be unprofitable, whereas 98.14 percent of the time, this project is lucrative and profitable for PXP. The only exception, again, is when production is at the worst-case scenario and output is close to a standstill.

- Figure 14.70, in contrast to the preceding figures, illustrates PXP's IRR on a pretax level. In the best-case scenario, PXP's IRR has a 100 percent chance of exceeding 55 percent, the required threshold for most high-risk projects such as undefined oil and gas exploration projects. Even in the most likely case, there is more than a 98 percent probability that the IRR exceeds PXP's hurdle rate of 25 percent, and in the worst-case scenario, a 45.80 percent chance of that occurring.

In summary, PXP's risks were nominal and the upside potential significant. To further decrease PXP's downside risks, David Mercier, chief of finance, economics, and accounting, and the economic consultant, Dr. Johnathan Mun, performed the real options analysis whereby PXP can start with three wells as a proof of concept to delineate the reservoir. If done properly, these three wells (limited total costs to drill, as compared to the total number of wells and injectors required in a full development) will help limit the downside risks and losses to PXP, while providing a significant upside. Therefore, the risks are mitigated, and, depending on the results of the three test wells, PXP can decide if it wants to pursue developing and completing all additional wells. Thus, the risks specified using simulation as previously illustrated would be diminished to a level that is close to zero, with the total loss being the expenses used to drill the three wells. The upside leverage is significant. For instance, say the total cost of drilling the three test wells is $53M. In the best-case scenario where 90 percent of the time at full production yields an NPV of $2.28B, PXP has leveraged its upside by almost 43 times. In the absolute worst-case scenario, the total losses for PXP will be the $53M spent on test drilling the three wells.

Strategic Real Options Analysis (Risk Mitigation) For PXP, if the best-case or most likely mid-case scenario occurs, its NPV value is still highly positive, indicating a profitable project in general. However, if the worst-case scenario occurs, with limited production, the project might end up being unprofitable. This is clearly a risk that PXP has to undertake, even with up to a projected 30 percent geological chance of failure (dry hole). To mitigate this risk, PXP can first drill three exploratory wells (Phase I in Figure 14.71). On the one hand, if these three wells prove to be successful (the reservoir

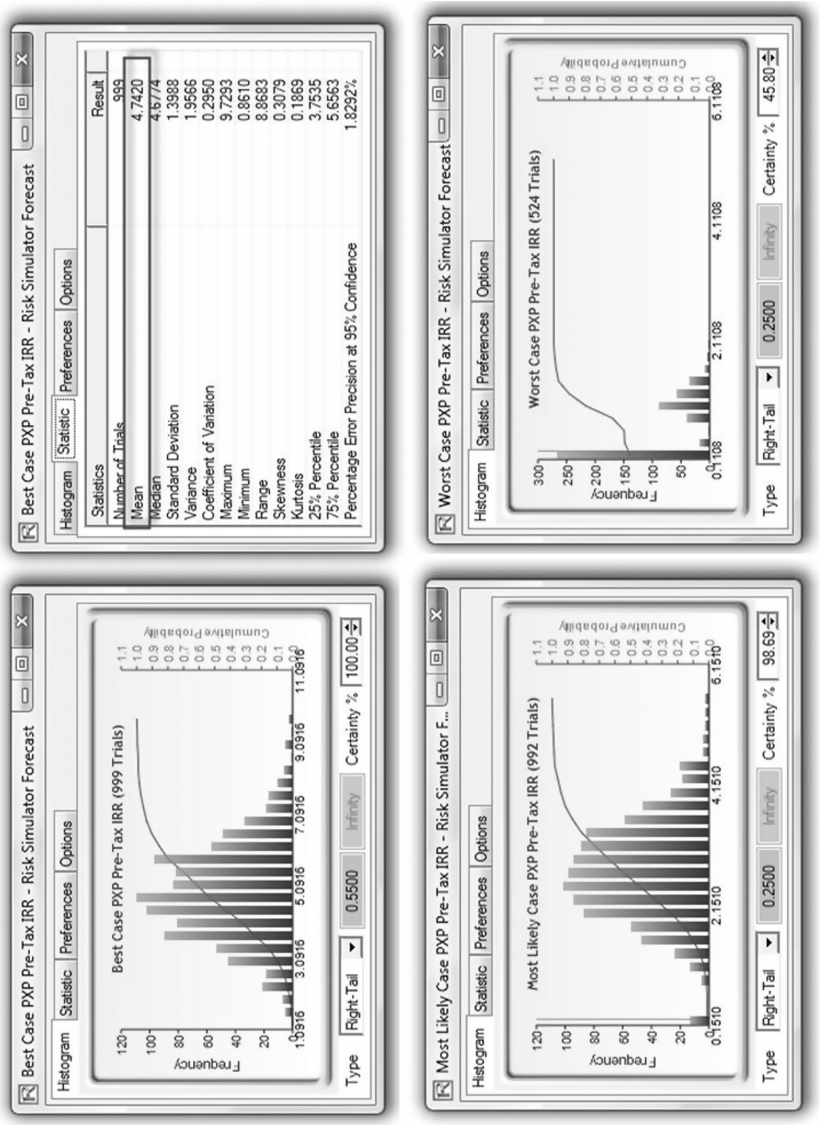


FIGURE 14.70 PXP's risk profile III (simulation results).

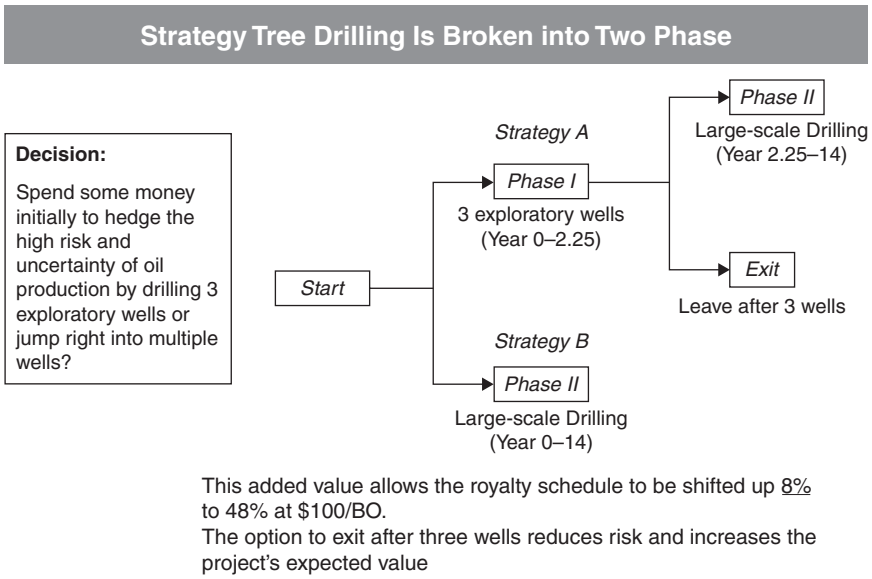


FIGURE 14.71 Sequential compound two-phased option.

is clearly delineated and the geological uncertainties of the reservoir are resolved and known), then PXP can pursue additional or large-scale drilling of the other wells in Phase II. On the other hand, if Phase I proves that there are issues with the reservoir, PXP can simply exit and abandon the drilling altogether. By creating a Phase I and Phase II development process, PXP can delineate the wells and reduce its risks. Instead of paying all of the capital expenditures immediately, the maximum that will be lost will be the cost to drill the three exploratory wells.

This risk mitigation technique is known in real options analysis as a sequential compound or phased option. This stage-gate process allows PXP to reduce its total losses should the worst-case scenario become reality, capping the total loss at three wells drilled, as compared to a large-scale development. By using this technique, the uncertainty and risks become resolved over the passage of actions, time, and events. PXP will and should optimally execute Phase II only if Phase I proves to be highly successful. Figure 14.72 illustrates the analysis performed to value the strategic option.

Optimal Royalty Rate Determination (Optimization and Scenario Analysis)
The next part of the analysis is the determination of the optimal royalty rate schema. The approach used was that of an optimization, where thousands of scenario combinations and permutations of royalty rates and PXP's IRR

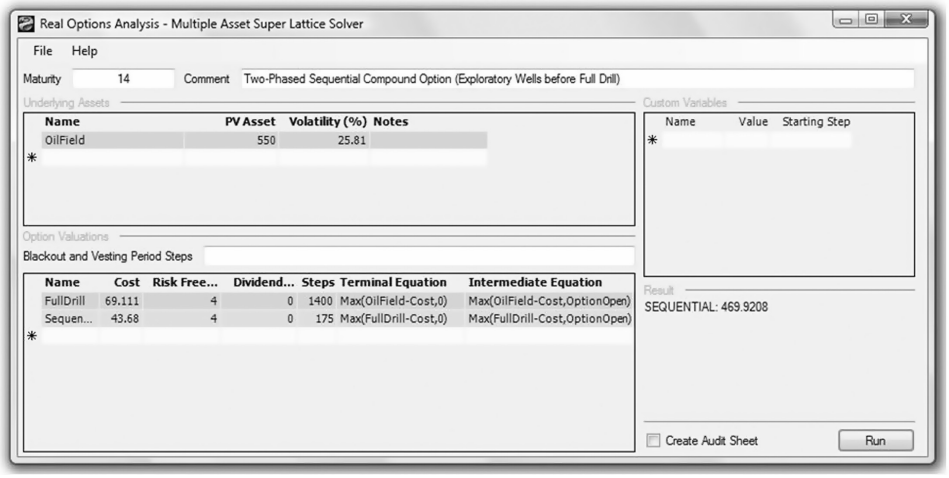


FIGURE 14.72 Real Options Valuation results.

were determined, and the optimal confidence band was determined. This band was developed to maximize the total NPV of the project while maximizing the returns to the state without leaving additional money on the negotiation table. At the same time, the constraint is such that PXP will still be profitable given these royalty rates. At rates higher than those in the optimal band, PXP will find the project unprofitable and the optimal decision is to abandon it. It is important to note that IRR was evaluated along with the many other financial metrics. (Note: A smaller investment and a better rate of return may have a higher IRR, but an investor's total wealth may be increased more with a larger investment and a lower IRR. Therefore, IRR doesn't provide any insight into the magnitude of the investment.) PXP's NPV was also considered in the sample optimization to ensure that it increases with increasing oil price. Figure 14.73 illustrates a small subset of these scenarios.

Analysis Conclusion

Based on the detailed economic and financial modeling performed by Staff and the economic Consultant, we came to the conclusion that the sliding royalty rate is the optimal scheme for the PXP project. The analysis took into consideration the risk and volatility of oil price and production decline rates, running stochastic simulations covering hundreds of thousands of potential outcomes, creating an optimization frontier of all possible combinations and permutations of oil prices and royalty rates.

Sample PXP IRR

Scenario Analysis Table

Output Variable: PXP AVG IRR **Initial Base Case Va** 0.47
Column Variable: Oil Price **Min:** 0.00 **Max:** 1.00 **Steps:** --- **Steps** 0.04 **Initial Base Case Value:**
Row Variable: Royalty Rate **Min:** 0.00 **Max:** 500.00 **Steps:** --- **Steps** 20.00 **Initial Base Case Value:**

	12%	16%	20%	24%	28%	32%	36%	40%	44%	48%	52%	56%	60%	64%	68%	72%	76%	80%	Calculated Royalty (%)
0	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	12.5%
20	-0.65	-0.68	-0.72	-0.75	-0.79	-0.83	-0.97	---	---	---	---	---	---	---	---	---	---	---	13.5%
40	-0.04	-0.10	-0.15	-0.21	-0.26	-0.32	-0.38	-0.43	-0.49	-0.55	-0.61	-0.68	-0.74	-0.82	---	---	---	---	28.4%
60	0.53	0.45	0.37	0.29	0.21	0.13	0.05	-0.03	-0.12	-0.20	-0.28	-0.37	-0.46	-0.54	-0.64	-0.73	-0.86	---	37.1%
80	1.10	0.99	0.89	0.78	0.67	0.57	0.46	0.35	0.25	0.14	0.03	-0.08	-0.19	-0.30	-0.42	-0.54	-0.66	-0.80	43.2%
100	1.66	1.53	1.40	1.26	1.13	1.00	0.87	0.74	0.60	0.47	0.33	0.20	0.06	-0.07	-0.21	-0.35	-0.50	-0.65	48.0%
120	2.21	2.06	1.90	1.74	1.59	1.43	1.27	1.11	0.95	0.80	0.64	0.47	0.31	0.15	-0.01	-0.18	-0.35	-0.52	51.9%
140	2.77	2.58	2.40	2.22	2.04	1.85	1.67	1.49	1.30	1.12	0.93	0.75	0.56	0.37	0.19	-0.01	-0.20	-0.40	55.2%
160	3.32	3.11	2.90	2.69	2.49	2.28	2.07	1.86	1.65	1.44	1.23	1.02	0.81	0.60	0.38	0.17	-0.05	-0.28	58.1%
180	3.87	3.64	3.40	3.17	2.94	2.70	2.47	2.23	2.00	1.76	1.53	1.29	1.05	0.82	0.58	0.33	0.09	-0.16	60.6%
200	4.42	4.16	3.90	3.64	3.38	3.12	2.86	2.60	2.34	2.08	1.82	1.56	1.30	1.03	0.77	0.50	0.23	-0.04	62.8%
220	4.97	4.68	4.40	4.11	3.83	3.54	3.26	2.97	2.69	2.40	2.12	1.83	1.54	1.25	0.96	0.67	0.37	0.08	64.9%
240	5.51	5.21	4.90	4.59	4.28	3.97	3.65	3.34	3.03	2.72	2.41	2.10	1.78	1.47	1.15	0.84	0.52	0.19	66.7%
260	6.06	5.73	5.39	5.06	4.72	4.39	4.05	3.71	3.38	3.04	2.70	2.36	2.02	1.68	1.34	1.00	0.66	0.31	68.5%
280	6.61	6.25	5.89	5.53	5.17	4.81	4.44	4.08	3.72	3.36	2.99	2.63	2.27	1.90	1.53	1.17	0.80	0.42	70.0%
300	7.16	6.77	6.38	6.00	5.61	5.22	4.84	4.45	4.06	3.67	3.29	2.90	2.51	2.12	1.72	1.33	0.93	0.54	71.5%
320	7.70	7.29	6.88	6.47	6.06	5.64	5.23	4.82	4.41	3.99	3.58	3.16	2.75	2.33	1.91	1.49	1.07	0.65	72.9%
340	8.25	7.81	7.38	6.94	6.50	6.06	5.62	5.19	4.75	4.31	3.87	3.43	2.99	2.55	2.10	1.66	1.21	0.76	74.2%
360	8.80	8.33	7.87	7.41	6.94	6.48	6.02	5.55	5.09	4.62	4.16	3.69	3.23	2.76	2.29	1.82	1.35	0.88	75.4%
380	9.34	8.86	8.37	7.88	7.39	6.90	6.41	5.92	5.43	4.94	4.45	3.96	3.47	2.97	2.48	1.99	1.49	0.99	76.6%
400	9.89	9.38	8.86	8.35	7.83	7.32	6.80	6.29	5.77	5.26	4.74	4.22	3.71	3.19	2.67	2.15	1.63	1.10	77.7%
420	10.44	9.90	9.36	8.82	8.28	7.74	7.20	6.66	6.11	5.57	5.03	4.49	3.95	3.40	2.86	2.31	1.76	1.21	78.7%
440	10.98	10.42	9.85	9.29	8.72	8.15	7.59	7.02	6.46	5.89	5.32	4.75	4.19	3.62	3.05	2.47	1.90	1.32	79.7%
460	11.53	10.94	10.35	9.76	9.16	8.57	7.98	7.39	6.80	6.20	5.61	5.02	4.42	3.83	3.23	2.64	2.04	1.44	80.7%
480	12.07	11.46	10.84	10.22	9.61	8.99	8.37	7.76	7.14	6.52	5.90	5.28	4.66	4.04	3.42	2.80	2.18	1.55	81.6%
500	12.62	11.98	11.34	10.69	10.05	9.41	8.77	8.12	7.48	6.84	6.19	5.55	4.90	4.26	3.61	2.96	2.31	1.66	82.5%

FIGURE 14.73 Sample optimal range of royalty rates developed by running thousands of alternate scenarios.

Other nonfinancial factors as well as factors such as the land donation, potential payment of additional county taxes, tax rebates and incentives, donation to develop certain green technology or environmental offsets (hybrid buses, parks, and the like) were outside the purview of this financial analysis, but are nonetheless important aspects in the negotiations.

Project Update

On January 29, 2009, the State Lands Commission voted down the project two (Lt. Governor Garamendi and State Controller John Chiang) against one (Deputy Finance Director Tom Sheehy). As of writing this case study, PXP has appealed to the State Legislature to get the State Lands Commission's vote overturned.

CASE STUDY: HOW REAL OPTIONS MITIGATES IT ENTERPRISE SECURITY RISKS

*This case was written by David M. Bittlingmeier (*david@bittlingmeier.com*). David has a B.S. from St. Mary's College and an M.S. from Golden Gate University, and has numerous years in strategic enterprise security, designing, developing, and implementing various enterprise policies and procedures, enterprise-wide security awareness training, business continuity, project management, and technical consultation experience, where he has provided professional judgments and advice to all levels of management. As a consultant, he has worked on ensuring compliance with industry best practices, business continuity, disaster recovery planning, ISO 17799, NIST standards, OCC, Basel II, BITS regulation, and has offered enterprise security management perspective for executives seeking an unbiased source of education, insight, and expertise in order to ensure the success of their business. In addition, he has consulted with (ISC)2, where he was both part of the team that developed/modified the training to prepare security professionals for the CISSP exam and then was/is a supervisor during the CISSP exams, wrote the strategic security plan for one of the major departments of the State of California, speaks at International Enterprise Security Conferences, is an ongoing attendee of the U.S. Secret Service San Francisco Electronic Crimes Task Force, was a contributor of Risk Analysis: 1st Step in HIPAA Security publication, as well as being a member of the High Technology Crime Investigation Association, Inc. David has received praise for his ability to explain complexity in lay terms from various sources such as San Francisco Mayor's Criminal Justice Council, California Youth Authority, and others.*