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November 7, 2007

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551

Attention: Vikie Bailey-Goggins
Administrator, Regulatory Operations

Re: **PacifiCorp's Report on the Feasibility of Stochastic Modeling for Net Power Costs**

In Order No. 07-446, entered October 17, 2007, on PacifiCorp's 2008 net power costs filing in Docket UE 191, the Commission adopted PacifiCorp's commitment to file a report on the feasibility of estimating net power costs using stochastic modeling within 15 business days after the issuance of the final order. PacifiCorp files this report in compliance with the order.

If you have any questions, please contact Joelle Steward, Regulatory Manager, at 503-813-5542.

Sincerely,

Andrea L. Kelly / JS

Andrea L. Kelly
Vice President, Regulation

Enclosures
cc: Service List for Docket No. UE 191

I hereby certify that on this 7th day of November, 2007, I caused to be served, via E-Mail and Overnight Delivery (to those parties who have not waived paper service), a true and correct copy of PacifiCorp's Report on the Feasibility of Stochastic Modeling for Net Power Costs in Docket No. UE-191-2008 Transition Adjustment Mechanism to the following:

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PacifiCorp Report on the Feasibility of Stochastic Modeling for Net Power Costs

Introduction

In Order No. 07-446 (entered October 17, 2007) on PacifiCorp's 2008 net power costs filing, the Commission adopted PacifiCorp's commitment to file a report on the feasibility of estimating net power costs using stochastic modeling within 15 business days after the issuance of the final order. PacifiCorp files this report in compliance with the order.

This report provides an overview of the background for the report, a description of the analysis of the modeling agreed to by the parties, a discussion of the issues related to the implementation of stochastic power cost modeling, and PacifiCorp's recommendation on the feasibility of the use of stochastic modeling of net power costs in rates. Attachment A is a technical report on parameter estimation, stochastic shocks and net power cost results.

Background

In the Partial Stipulation in PacifiCorp's 2005 general rate case, Docket UE 170, approved in Order No. 05-1050 (entered September 28, 2005), the Company made a commitment to evaluate stochastic modeling of net power costs for possible incorporation into rates. Section 5a of the Partial Stipulation stated the following:

> The Parties further agree that PacifiCorp will commit sufficient resources during the year following the approval of this Partial Stipulation to permit the evaluation of stochastic modeling of Net Power Costs for possible incorporation into rates. The analysis will consider the volatility of hydro generation, electricity prices, natural gas prices, system load and forced outages as well as the correlations among these variables. PacifiCorp, with input from Staff, will develop a plan to complete the evaluation of stochastic modeling, including a schedule of quarterly public workshops to provide progress reports and receive inputs from interested parties. This Partial Stipulation does not address the appropriateness of introducing stochastic modeling of Net Power Costs into rates.

On November 22, 2005, the Company and Staff met to establish a plan for evaluating stochastic net power cost modeling. As a result of this meeting, the Company agreed to do the following:

1. Select a high quality data set based upon statistical analysis.
2. Adjust the linear program optimizing equations used in the Integrated Resource Planning process to remove parts related to long-term effects.
3. Compare deterministic studies of the GRID model used for ratemaking and the PaR model used for the IRP given a consistent set of data.
4. Develop correlations among electricity market prices, natural gas market prices, hydro conditions, load profiles and unplanned unit outages.
5. Develop 100 sets of variables for running GRID and prepare stochastic results.

Workshops were held with the parties during 2006 to discuss the analysis prepared by the Company for items one through four, in preparation of the stochastic analysis. This report summarizes the process and results of the stochastic studies.

Stochastic Modeling Analysis and Results

Based on the discussions with parties during 2006, the Company developed a data set from the 48-month period ending September 2005 to derive the statistical characteristics of the stochastic variables. The PaR model was used to estimate the stochastic parameters that drove the inputs into the calculations of net power costs, and GRID was used to determine the net power costs. The primary reason for using two different models was due to the inability of GRID to perform stochastic analyses while also being the tool used to develop net power costs for retail rates. To ensure the consistency and reasonableness of the inputs generated from variables estimated by PaR and for use in GRID, the Company performed reconciliation between the two models on a deterministic basis, and determined that the results were acceptable.

In order to obtain sufficient net power cost results to reach a conclusion within a reasonable period of time, the variables with uncertainties were divided into two categories based on their degrees of correlation. Market electricity prices, natural gas prices, hydro generation and load are in one category, and thermal forced outages in another. For the first category of variables, 100 possible stochastic scenarios of variables were drawn from PaR that were further grouped and reduced to 20 sets of inputs into GRID. For each of those 20 inputs, there were three levels of thermal forced outages. In total, 60 GRID runs were performed. The detailed statistical characteristics of the net power cost results are presented in Attachment A.

A version of the Company's net power costs calculated in UE 179 was used as the base for comparison and non-stochastic variables. Using the non-stochastic variables from the base run plus the stochastic variables from PaR, the stochastic net power costs range from $585 million to $1,207 million, with the expected value of $844 million. The deterministic base net power cost is $838 million. That is, the expected value of the stochastic net power costs is about $6 million higher than the deterministic net power costs. Separate studies were done excluding the Company's natural gas positions that vary with market conditions. Similar differences occurred in those studies.

The key finding from the Company's study was that stochastic power cost modeling produced comparable results to the Company's deterministic power cost modeling. Some parties have previously argued that stochastic modeling would lower net power costs by capturing the extrinsic value of generation resources. See, e.g., Order No. 07-015 at 11. Others have suggested that stochastic modeling had the potential to increase NVPC forecasts because deterministic models were more likely to underestimate than overestimate NVPC. *Id.* at 10-11. The Company's study indicates that stochastic modeling introduces a range of new variables which offset each other sufficiently to produce an expected value that largely mirrors the results of a deterministic model. While a flexible resource portfolio is able to take advantage of favorable events and minimize the impact of unfavorable events in its operating environment, such flexibility is limited and events in the operating environment behave differently. For example, market prices and thermal outages have a lower bound of zero, but they do not have a clearly defined upper bound, in general. Even if the favorable and unfavorable events have a symmetrical distribution, their impact on net power costs are not necessarily symmetrically distributed.

Provided as Attachment A is a technical report on parameter estimation, stochastic shocks and net power cost results.

Implementation Issues

There are three notable obstacles to making stochastic power cost modeling for ratemaking feasible. First, the staffing required to perform the study with the current technological constraints is a significant hurdle. The current study required close to 400 hours of work. Repeating the study may be somewhat less time consuming because new cases can build off the study's spreadsheet tools and analysis. However, as new data sets are required over time and with the changing energy markets, there will be a need to regularly rework the design of the modeling. Further, there would be significantly more hours required to process a rate proceeding because of the hundreds of individual power cost model runs required to forecast NVPC and develop transition credits for direct access customers using a stochastic modeling approach. Responding to requests for additional studies and revisions from Staff and intervenors will present greater challenges.

Second, GRID is not capable of handling mass storage that is required of the stochastic modeling and it does not have a stochastic engine. The current study utilizes the PaR model's stochastic capabilities to perform the front-end of the study and generate inputs for GRID. Unfortunately, the GRID and PaR inputs, though conceptually based on similar principles, are not identical. PaR stochastic inputs do not feed directly into the GRID model. Rather the stochastic factors generated by PaR have to be applied to the GRID inputs. To have the entire study to be feasible within GRID alone would require a significant re-architecture of the GRID model and a significant upgrade in its database capabilities.

Third, the expertise required to run and analyze the results of stochastic modeling is significant. Implementing such a methodology in ratemaking processes would increase the technical challenges associated with preparation and analysis of the Company's power cost filings and imply the need for experts with strong econometric backgrounds. This is especially true for the Company since it has the burden to demonstrate, justify and defend the statistical nature of the variables that are used in a rate proceeding, including but not limited to time period and size of the data set used to define the statistical characteristics, distributions and correlations of the variables, number of data sample generated by PaR, and number of GRID runs. The technical expertise required to prepare, analyze and verify the stochastic portion of the study requires a minimum of graduate level econometrics, a level of expertise difficult to find in the general workforce.

Conclusion

The Company has found the analysis prepared for this report to be very informative, especially on the issue of modeling the extrinsic value of generation resources.

The key finding of the Company's study is that there is only a small variance between the results of the Company's stochastic modeling and deterministic modeling. This suggests two important conclusions. First, it is an important validation of the current deterministic approach to modeling NVPC. Second, given the significant resources and complexity involved in developing and implementing stochastic modeling, it suggests that implementation of stochastic modeling may not be cost-effective or advisable. This is particularly true for PacifiCorp, given the additional challenges created by its multi-state status. As discussed above, the expected value of net power costs from the stochastic modeling produced total Company results that were $6.4 million higher than those produced by a deterministic GRID run, which is currently used to develop net power costs for rates. However, it is unlikely that stochastic modeling would be adopted by other jurisdictions served by the Company. On an Oregon allocated basis, net power costs would be higher by approximately $1.7 million. This result does not provide a reasonable justification for continued analysis and implementation of stochastic modeling of net power costs in rates.

ATTACHMENT A

SUBJECT: Stochastic Net Power Costs Technical Workgroup – Parameter Estimation, Stochastic Shocks and Net Power Cost Results

First, is stochastic modeling, as it is practiced for resource planning, appropriate for normalized ratemaking? One of the primary focuses for resource planning is stress testing different resource portfolios under conditions of uncertainty. Under uncertainty, resource portfolios that do not include assets with inherent flexibility, i.e., extrinsic value, or high option value, will under perform portfolios with those assets and thus be required to increase system balancing costs. In normalized ratemaking the emphasis has traditionally been on setting rates based on the expected operation of the utility's system under normal conditions, not under uncertainty. A crucial reason being that utilities are in a better position than are customers to calculate, bear and respond to energy market fluctuations. These are the same market fluctuations that IRP modeling attempts to simulate in an effort to put the utility in a reasonably hedged and risk robust position on a forward basis, but that are traditionally excluded as costs that the utility can recoup. The methodology used in this study attempts to address this issue by squelching much of the system balancing costs and taking a structural view of the stochastic processes already generated. Figure 9 provides an example of this squelching using the shocks to Utah loads. The comparison here is between the iterations that make up the particular stochastic level and the particular stochastic level over the test period on a weekly basis. The volatility squelching is evident and expected given the stochastic level is simply the arithmetic average of the ranked iterations.

Summary

Section 1 presents the stochastic process used to generate the variable shocks and the econometrics used to estimate the required input parameters. The stochastic process is applied to natural gas and power prices, retail loads by state and hydro generation. This approach is consistent with PacifiCorp's integrated resource planning (IRP) that varies these same variables for evaluation of different resource portfolios under the conditions of uncertainty. The current study also uses the company's IRP model, Global Energy's Planning and Risk (PaR), for generation of the variables' shocks. Section 2 provides illustrative results of the stochastic process (the remainder of the results are provided in the Appendices). Section 3 provides the modeling of the only variable not modeled within PaR – stochastic forced outages. The forced outage modeling is identical in specification used in the company's 2007 IRP, except that it is generated in an Excel spreadsheet and uses a modified convergent Monte Carlo method. Section 4 demonstrates the methodology, a methodology that is appropriate for normalized rate-making purposes, used for inputting the shocked variables into the GRID model. Finally, Section 5 presents the results of the study and an evaluation of possible stochastic power cost modeling in regulatory proceedings.

1.0 The Stochastic Model and Parameter Estimation

The current study uses PaR's stochastic model to generate 100 varying potential time paths. These are then ordered and segregated by a weighted average of the individual impact runs from GRID, and applied to the appropriate GRID input data series. The individual impact run is a GRID sensitivity run of a one percent increase in the underlying variable, and then calculating a straightforward weighting vector that is applied to all 100 PaR simulations. The weighting vector and its application to the 100 simulations are discussed in Section 4. As for PaR's simulations, during model execution, simulations are time path dependent Monte Carlo draws for each stochastic variable based on the input parameters. The Monte Carlo draws are then transformed into percentage deviations from the expected value of the variables. In the case of natural gas prices, electricity prices and regional loads, PaR applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

1.1 The PaR Stochastic Model

PaR's stochastic model is a two factor (a short-run and a long-run factor) short-run mean reverting model. Variable processes assume normality or log-normality as appropriate. Separate volatility and correlation parameters are used for modeling the short-run and long-run factors. The short-run process defines seasonal effects on forward variables, while the long-run factor defines random structural effects on electricity and natural gas markets, regional retail loads and regional hydro generation. The short-run process is designed to capture the seasonal patterns inherent in electricity and natural gas markets and on electricity demand. As defined in equation (4) and (5) below, the interdependence between the variables is captured through the short-run and long-run correlation matrices that impact the generation of the shock term defined in equations (1) and (2). Mean reversion represents the speed at which a disturbed variable will return to its seasonal expectation. With respect to the long-run factor, the Monte Carlo draws applied to natural gas and power prices define a possible forward equilibrium level. Long-run shocks to regional electricity loads define possible forward paths for electricity demand; while long-run shocks to hydro generation represent possible intra-regional weather and climate impacts to underlying streamflows as well as generation performance.

Parameter estimates are based upon the data set presented in the first meeting of the technical workgroup. The realization for the data set is the 48-months ending September 2005. The data set consists of daily measurements of Dow Jones Natural Gas and Power Market prices, Hydro Generation, Loads Requirements by State and Forced Outages for the 48 month period ending September 2005. The data set has been revised to eliminate non-trading day observations, weekend and holiday forward prices and missing/erroneous recordings. Also of note is the additional inclusion of balance of the month ("BOM") forward prices used for estimating the price series parameters.

The PaR stochastic two-factor model (see Pilipovic, 1997 for a detailed specification) is specified below:

(1) $$S_{i,t} = S_{i,t-1} + L_{i,t} - L_{i,t-1} + \alpha_{i,t}\left(L_{i,t-1} - S_{i,t-1}\right) + \sigma^S_{i,t}\varepsilon^S_{i,t_t} + (c.e.)$$

(2) $$L_{i,t} = L_{i,t-1} + \sigma^L_{i,t}\varepsilon^L_{i,t} + \left(c.e.\right)$$

Where (1) is the short-run factor and (2) is the long-run factor, $\varepsilon_{i,t}$ is the random shock, and *c.e.* is a constant error term

(3) $$E[\varepsilon^S_{i,t}\varepsilon^L_{i,t}] = Cov^{S,L}_{i,t} = 0$$

(4) $$E[\varepsilon^S_{i,t}\varepsilon^S_{j,t}] = Cov^S_{i,j,t} \neq 0$$

(5) $$E[\varepsilon^{L}_{i,t}\varepsilon^{L}_{j,t}] = Cov^{L}_{i,j,t} \neq 0$$

Where, following (3) the short-run and long-run factors are uncorrelated (the relationship between the short and long-run is modeled explicitly in equation (1)), and per (4) and (5) variables are correlated; short-run seasonally and long-run annually. The subscript *I* differentiates between variables (Mid Columbia power prices versus Wyoming retail loads), while subscript *t* observations within the realization.

The objective for this portion of the study is to develop input parameters for the stochastic simulation process, present the input parameter analysis and present some detailed examples of the stochastic simulation. In general terms the simulation process requires a set of short-run and long-run volatility and correlation inputs. These inputs are generated through the following econometric analysis.

1.2 Econometric Estimation Specification

PaR's short-run parameter estimation is based on the following continuous time definition.

(1) $$dy_t = \alpha(\bar{y} - y_t)dt + \sigma_{y,t}dz_t$$

Where $\bar{y} = E[y_t]$, α is the mean reversion parameter and σ is the short-run volatility parameter.

In this case the discrete time model representation is:

(2) $$S_t - S_{t-1} = \alpha(L - S_{t-1}) + \sigma\varepsilon_t$$

Where L is the expected equilibrium of S_t.

Econometric estimation of (2) uses the specification of equation (3):

(3) $$\Delta S_t = a + bS_{t-1} + e_t$$

Where the b is the mean reversion parameter, and the volatility metric is the standard error of the regression based on e_t

The continuous time definition of the long-run process is:

(4) $$dL_t = \mu L_t dt + \theta_{L,t}dw_t$$

Where θ is the equilibrium volatility and μ is the expectations operator.

The long-run discrete time representation is:

(5) $$L_t - L_{t-1} = \mu + \varepsilon_t$$

Econometric estimation of (5) uses the specification of equation (6):

(6) $$\Delta L_t = a + e_t$$

Where *a* is the expectations parameter (in *random walk* nomenclature, this is the drift rate) and the volatility metric is the standard error of the regression based on e_t

In summary, equation (3) is used to estimate the short-run effects, while (6) is used to estimate the long-run effects.

Short-run parameters for the hydro and load variables are estimated using equation (3) from above. Given the specification of (3), the mean reversion for the variable is simply the negative of the AR(1) coefficient. The volatility parameter is the standard error of the regression for each variable separated by seasonal periods. With respect to the price variables, the previous trading day's spot price alone underestimates the speed at which the power and natural gas markets return to the equilibrium path after a perturbation.[1] The use of balance of the month (BOM) forward prices facilitates correct estimation of the mean reversion speed. As a result, the econometric specification for the price series estimation is:

$$(7) \qquad \Delta(S_t - F_t) = a + b(S_{t-1} - F_{t-1}) + e_t$$

Where F_t is the forward BOM price and the volatility metric is the standard error of the regression based on e_t

1.3 Parameter Estimates

Table 1 below provides a summary of the short-run parameters. Heteroscedasticity is an issue to greater or lesser extant within all variable categories. Thus, parameter estimation utilizes the seemingly unrelated regression (SUR) methodology within the variable categories (Power, Natural Gas, Hydro and Loads). The SUR methodology accounts for heteroscedasticity and simultaneous correlation for the errors across equation variables (Greene, ____). Further the

Table 1. Short-Run Parameter Estimates

ST Volatility & Mean Reversion Summary	Fall		Winter		Spring		Summer	
	Volatility	Mean Reversion	Volatility	Mean Reversion	Volatility	Mean Reversion	Volatility	Mean Reversion
Power								
4C	0.0993	0.58	0.0926	0.58	0.0940	0.61	0.0974	0.44
COB	0.0637	0.62	0.0854	0.54	0.1231	0.46	0.0919	0.43
MIDC	0.0806	0.57	0.0847	0.44	0.1569	0.42	0.1175	0.29
PV	0.1079	0.52	0.1046	0.40	0.0900	0.48	0.0939	0.42
Natural Gas								
East - Opal	0.0953	0.37	0.0587	0.40	0.0892	0.32	0.0423	0.29
West - Malin	0.0702	0.34	0.0545	0.46	0.0374	0.28	0.0349	0.38
Hydro								
MIDC	0.2005	0.56	0.1772	0.54	0.1944	0.44	0.1747	0.32
PACE	0.2487	0.20	0.1589	0.26	0.1639	0.05	0.1205	0.04
PACW	0.2001	0.12	0.1906	0.18	0.1462	0.12	0.1742	0.17
Loads								
CA	0.0519	0.13	0.0532	0.18	0.0574	0.11	0.0482	0.23
ID	0.0462	0.23	0.0405	0.27	0.0510	0.05	0.0539	0.08
OR	0.0342	0.17	0.0434	0.28	0.0343	0.17	0.0405	0.29
UT	0.0357	0.17	0.0259	0.23	0.0283	0.09	0.0446	0.14
WA	0.0399	0.20	0.0515	0.24	0.0378	0.19	0.0527	0.23
WY	0.0193	0.10	0.0250	0.13	0.0219	0.10	0.0187	0.08

The long-run estimates are based on the same 48-month data set as the used in the short estimations. In the case of long horizon modeling, such as Integrated Resource Planning (IRP), the long horizon has significant impact, accounting for the largest impact in stochastic results. For calibration of long-run volatility, estimates are often matched against some metric of market implied forward volatility, thus balancing historical information with market expectations. However, for a single year net power cost study, the long-run factor only functions to disturb the test year's equilibrium. Because of this the long-run factor is estimated using the same 48 month data set. Table 2 below summarizes the long-run parameters.

Table 2. Long-Run Parameter Estimates

LT Volatility Summary	LT Volatility
Hydro	
MIDC	0.0135
PACE	0.0118
PACW	0.0118
Loads	
CA	0.0035
ID	0.0032
OR	0.0025
UT	0.0023
WA	0.0031
WY	0.0014

Given the parameter estimation, the fitted residuals are correlated for the seasonal and long-term variables. The correlation of the regression residuals is also tested for decomposability in PaR's stochastic model. If a given correlation matrix was not decomposable, it is adjusted with the appropriate scalar eigenvalue adjustment. In the present study the long-run, fall, winter and summer correlations were adjusted for decomposability. Note that the eigenvalue adjustment does nothing to change the structure of the relationship among the variables; the scalar applies equally across all variables in the matrix. Presented below in Table 3 is the long-run correlation matrix.

Table 3. Long-Term Correlation Estimates

LT Correlations	L - Idaho	L - Utah	L - Washington	L - West Main	L - Wyoming	P - 4C	P - COB	P - MidC	P - PV	P - NG E	P - NG W	H - MidC	H - PACE	H - PACW
L - Idaho	1	0.2682	0.1659	0.1737	0.1217	0.0405	0.0284	0.0334	0.0245	0.0519	0.0541	0.0179	-0.0782	0.0299
L - Utah	0.2682	1	0.2239	0.2673	0.2640	0.2434	0.1751	0.1569	0.2266	-0.0196	0.0367	0.0660	-0.0497	0.1023
L - Washington	0.1659	0.2239	1	0.5952	0.1868	0.0993	0.1683	0.1602	0.0807	-0.0045	0.1281	0.0902	-0.0427	0.1910
L - West Main	0.1737	0.2673	0.5952	1	0.1853	0.1531	0.2204	0.2270	0.1367	-0.0049	0.0971	0.0951	-0.0450	0.1798
L - Wyoming	0.1217	0.2640	0.1868	0.1853	1	0.0779	0.0783	0.0673	0.0669	0.0097	0.0307	-0.0002	-0.0292	0.0334
P - 4C	0.0405	0.2434	0.0993	0.1531	0.0779	1	0.7103	0.5996	0.8685	0.1067	0.2588	-0.0453	0.0002	0.0255
P - COB	0.0284	0.1751	0.1683	0.2204	0.0783	0.7103	1	0.7707	0.7285	0.1012	0.2772	-0.0652	0.0007	0.0269
P - MidC	0.0334	0.1569	0.1602	0.2270	0.0673	0.5996	0.7707	1	0.6262	0.0579	0.2587	-0.0924	-0.0079	0.0231
P - PV	0.0245	0.2266	0.0807	0.1367	0.0669	0.8685	0.7285	0.6262	1	0.1155	0.2593	-0.0612	0.0136	0.0185
P - NG E	0.0519	-0.0196	-0.0045	-0.0049	0.0097	0.1067	0.1012	0.0579	0.1155	1	0.5012	0.0372	-0.0080	-0.0114
P - NG W	0.0541	0.0367	0.1281	0.0971	0.0307	0.2588	0.2772	0.2587	0.2593	0.5012	1	0.0733	-0.0358	0.0174
H - MidC	0.0179	0.0660	0.0902	0.0951	-0.0002	-0.0453	-0.0652	-0.0924	-0.0612	0.0372	0.0733	1	-0.0618	-0.0183
H - PACE	-0.0782	-0.0497	-0.0427	-0.0450	-0.0292	0.0002	0.0007	-0.0079	0.0136	-0.0080	-0.0358	-0.0618	1	0.0693
H - PACW	0.0299	0.1023	0.1910	0.1798	0.0334	0.0255	0.0269	0.0231	0.0185	-0.0114	0.0174	-0.0183	0.0693	1

The highlights denote correlations that are significant at the 5% level. As is expected, correlations for sudden deviations – shocks – are insignificant for hydro and market power prices. However, among all other variable categories – loads, power prices and natural gas – there is a significant structural relationship. Provided in Part 1 of Appendix A are the seasonal correlations.

2.0 The Stochastic Shocks

With the finalized correlations and the statistical parameters input into PaR and consistent with the proposal made to OPUC staff the company used PaR's stochastic engine to create 100 iterations for use in the GRID model. In the case of loads, power price and natural gas prices shocks are applied for each day within the test period. Hydro shocks are applied on a weekly basis. Following standard Global Energy practice, the price variables, the natural gas and power prices, assume a log-normal distribution, while loads and hydro generation assume normality.

Figures 1 and 2 present the distribution of the load shocks for Utah and West Main (the remainder of the distributions are available in Part 2 of Appendix A). The horizontal axis defines the bin range for the histogram while the vertical axis defines the number of occurrences. Both Utah and West Main approximate a normal distribution.

Figure 1. Distribution of Utah Load Shocks

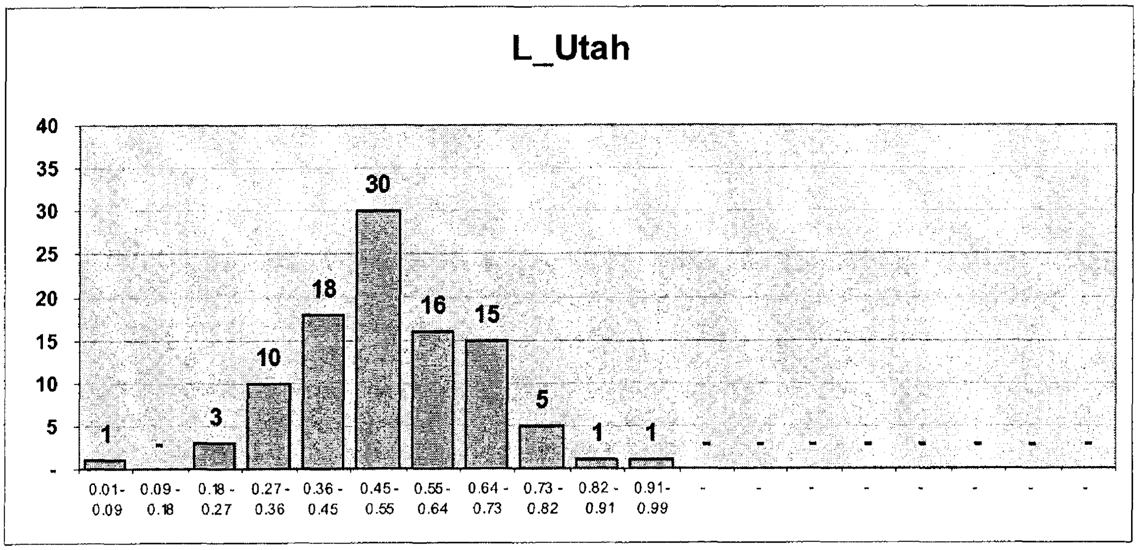
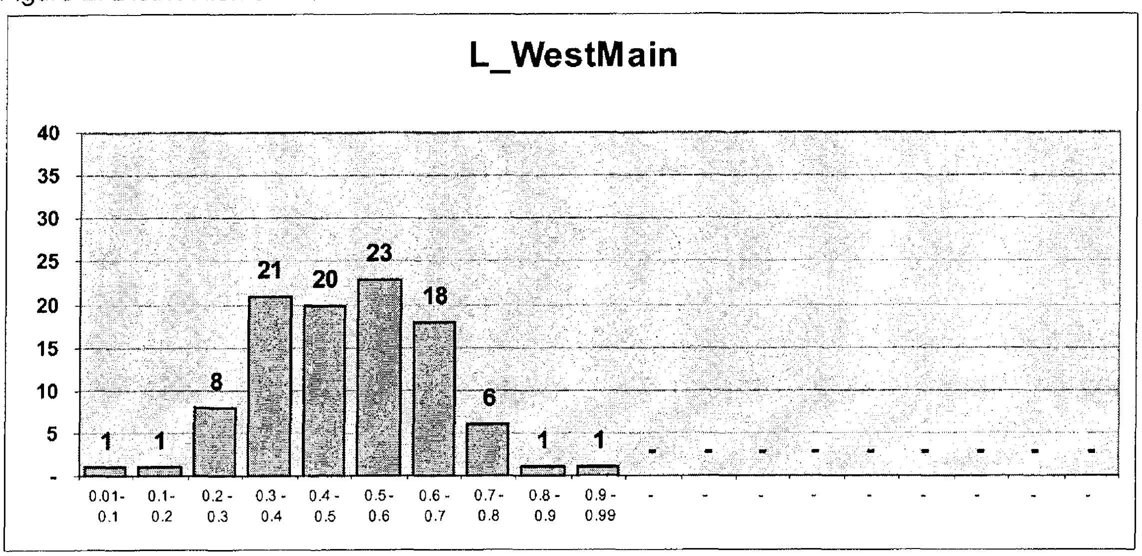


Figure 2. Distribution of West Main Load Shocks



Though the bin ranges are different, what the figures show is that the West Main loads have fatter tails and less concentration around a central point. This is expected given the relative difference in seasonal winter volatility; West Main is nearly twenty percent more volatile.

Figures 3 and 4 provide the histograms of the stochastic shocks for the Mid-Columbia and Four Corners power markets. Both markets show significant skewness to the right, which typifies the log-normal distribution for price variables. Also, with respect to inter-market variation, the stochastic process generated at least one extreme value for the Mid Columbia shocks and shows relatively greater variability, while the Four Corners market presents the classic log-normal distribution. Again, this is an expected result given the increased volatility in the spring and summer and the comparative sluggishness of the Mid Columbia market's mean reversion rate.

Figure 3. Distribution of Mid Columbia Power Price Shocks

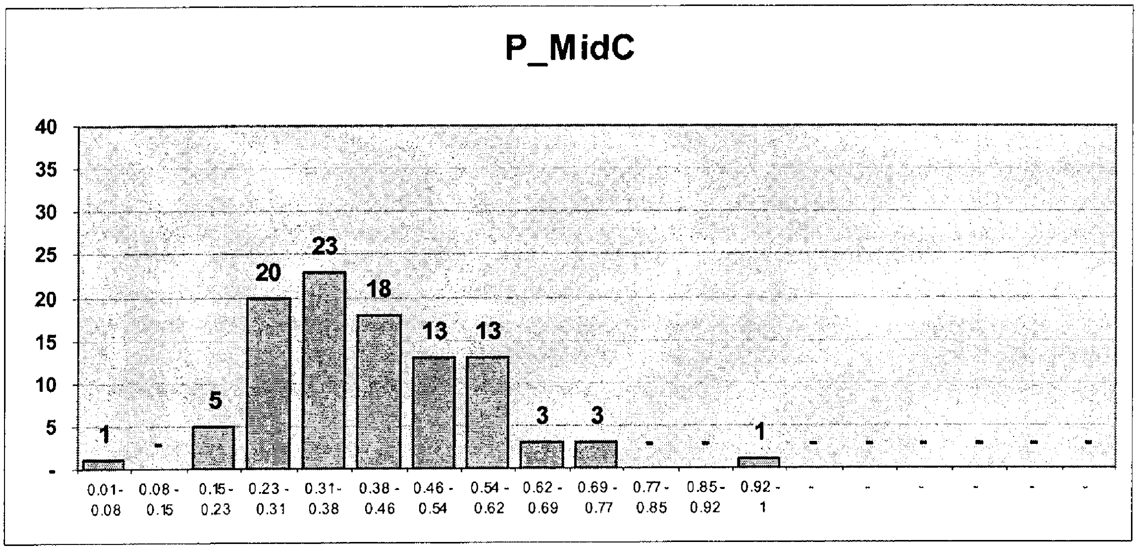
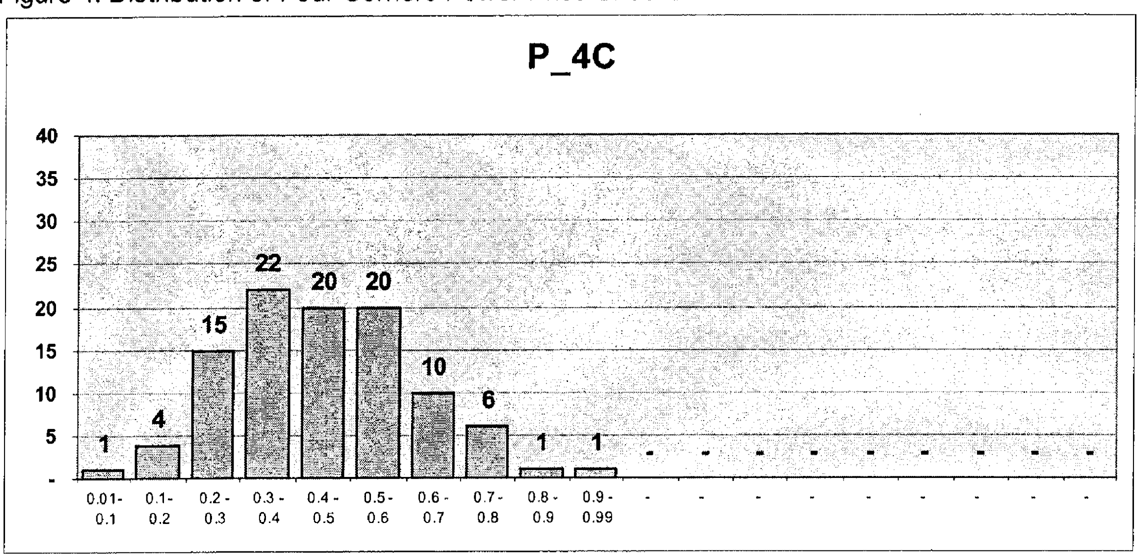


Figure 4. Distribution of Four Corners Power Price Shocks



The remainder of the price distributions are provided in Part 2 of Appendix A.

Figures 5 and 6 show the distribution of hydro generation for PacifiCorp's Mid-Columbia contracted hydro generation and the western control area's owned hydro generation.

Figure 5. Distribution of Mid-Columbia Hydro Generation Shocks

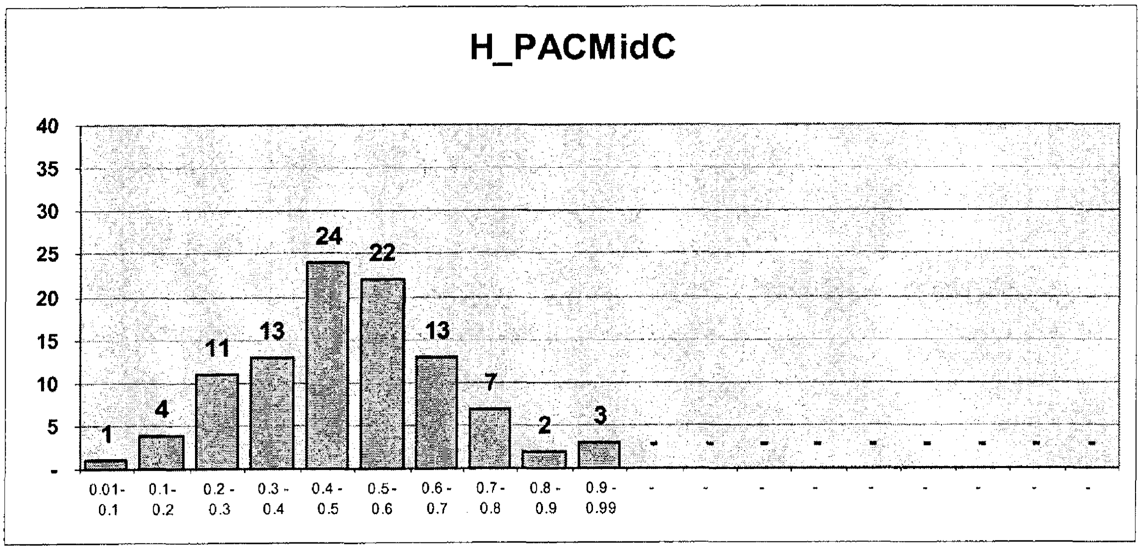
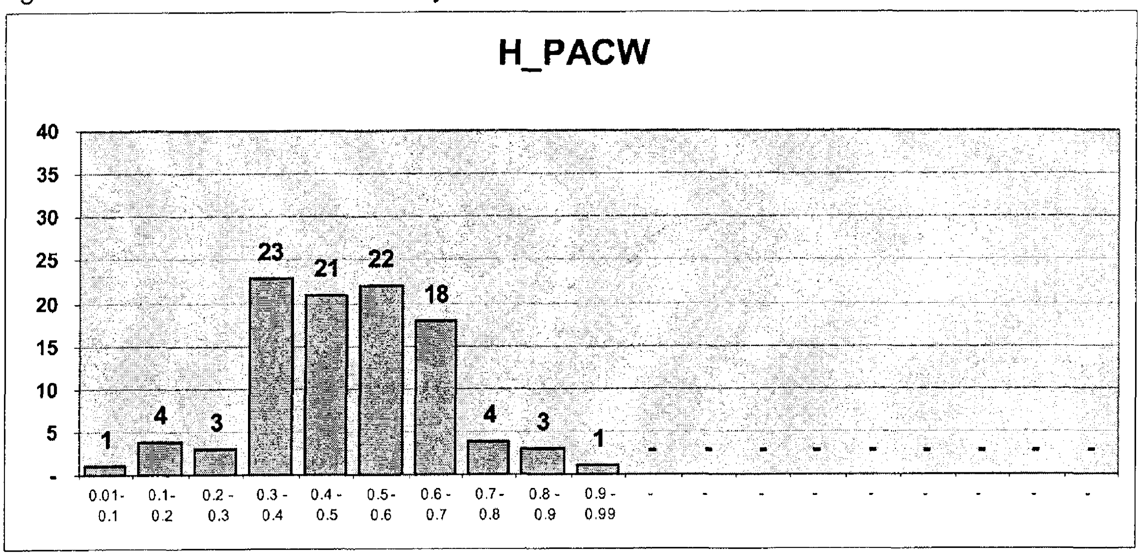


Figure 6. Distribution of PAC West Hydro Generation Shocks



The company's owned hydro generation shows significantly less variation than is expected from the volatility inputs. This is highlighted when compared to the Mid-Columbia generation. The reason for these distribution effects is the strong correlation between loads and company owned hydro generation (most of the significant correlations with hydro variables are with PAC West hydro, see Table 3 and Part 1 of Appendix A).

3.0 Forced Outages

The outage rate calculations are based on the same method the company currently employs for IRP modeling. The method uses daily average derated states of the company's thermal unit for the 48 month period ending September 2005. Consistent with the company's IRP modeling of stochastic outages, six operating state frequency distributions are developed for each unit. Then using a uniform random number, 100 draws are generated for each unit on a weekly basis and scaled so that the expectations of the simulated states are equal to the historical estimates. Figures 7 and 8 show two of the company's units, Hunter 1 and Colstrip 3. Interpretively, Hunter 1 runs at its average maximum dependable capacity 42.3% of the time, while the unit experiences a full forced outage 7.1% of the time. The pattern is noticeably different for the Colstrip unit, which only runs at its average maximum dependable capacity 10.6% of the time and runs at an approximate 2.7% derate 63.6% of the time.

Figure 7. Hunter 1 Percentage Expectations for Generation Levels

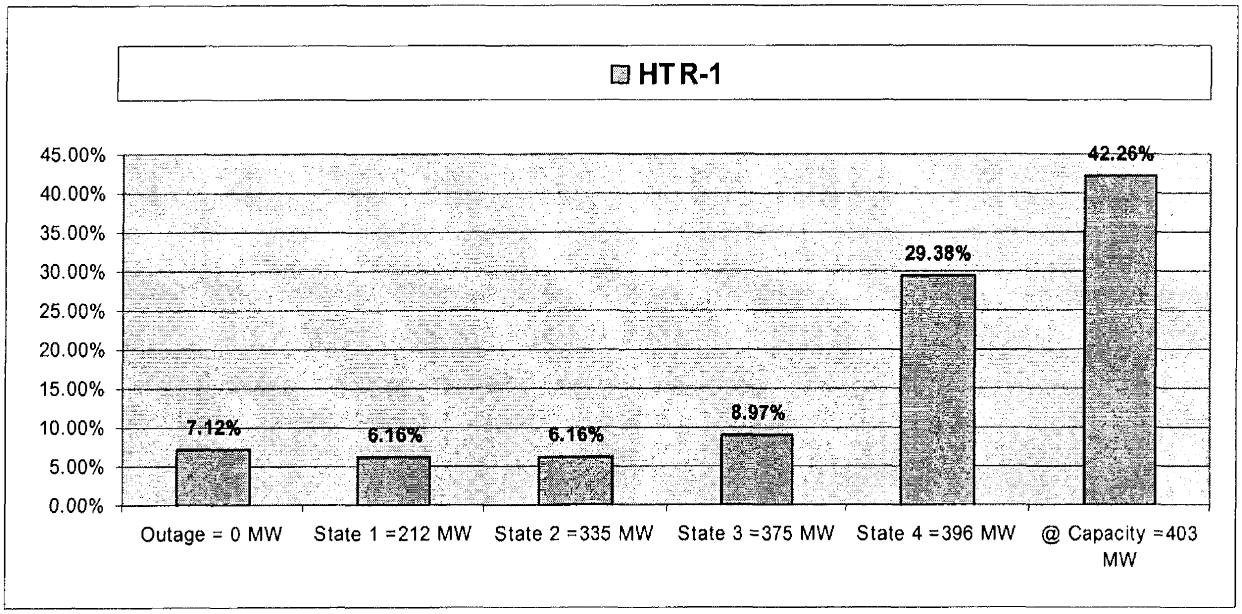
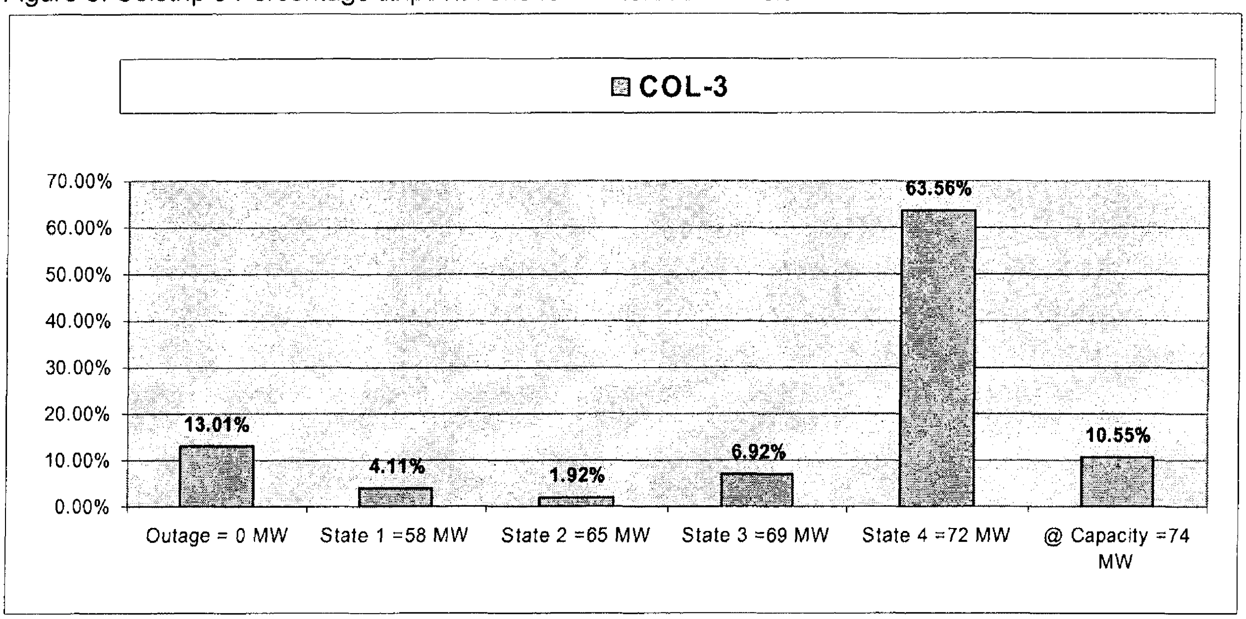


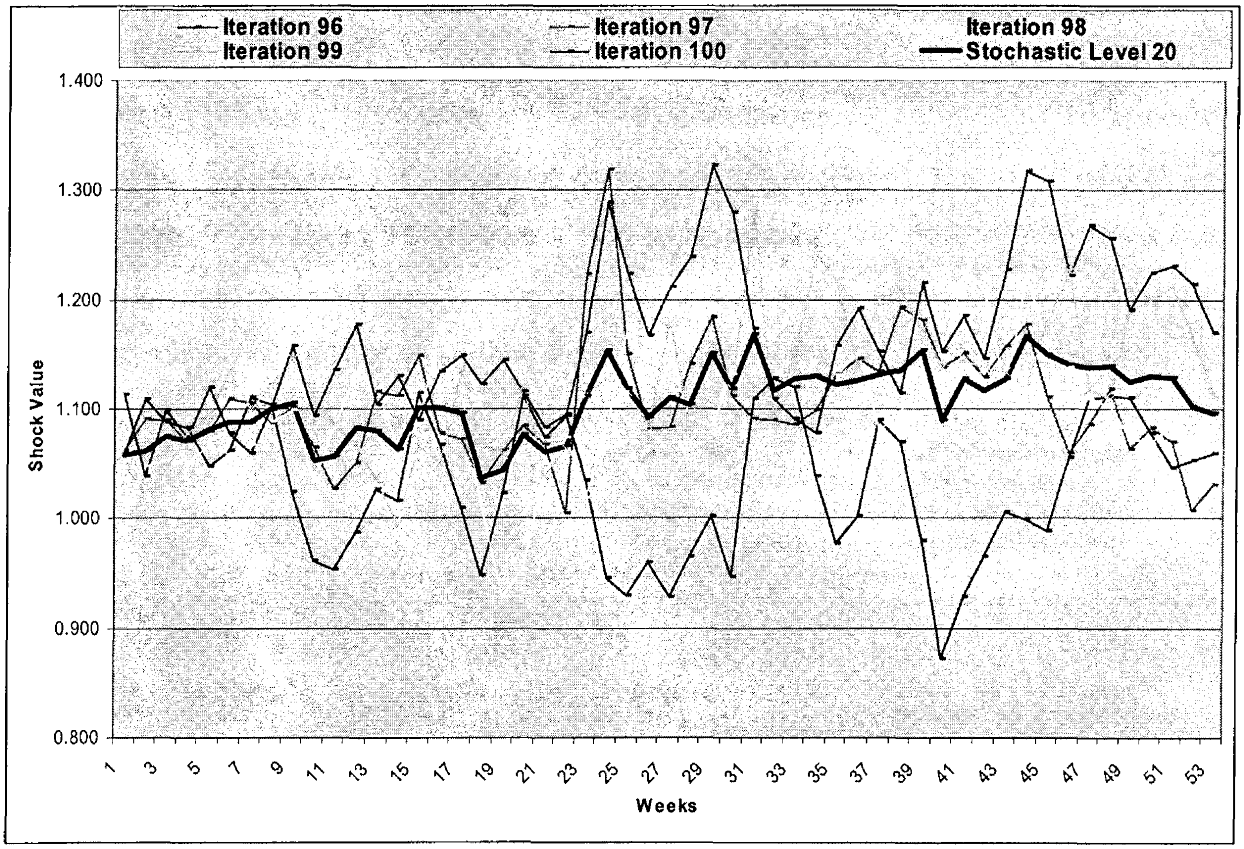
Figure 8. Colstrip 3 Percentage Expectations for Generation Levels



4.0 Stochastic Application for the GRID Model

At this point in the study a great deal of information has been generated through the stochastic studies of the various inputs to power cost modeling. The methodology used for inputting the variables into the GRID model in this study takes a structural view of the stochastic processes. Figure 9 provides an example of the methodology using the shocks to the Utah loads. The comparison here is between the iterations that make up the particular stochastic level and the particular stochastic level over the test period on a weekly basis. There is evident volatility squelching, with the stochastic level being the arithmetic average of the ranked iterations, but this does capture the structural effects of the stochastic shocks.

Figure 9. Comparison between Individual Iterations and Stochastic Levels



A second issue is purely technical. Because the 100 iterations generated through PaR's stochastic engine and the 100 iterations needed for the forced outage modeling are completely independent (the theoretical correlation is zero), the total number of simulations would have been 10000. Under the current GRID software specification, it is infeasible to input two sets of 100 model run definitions and run and store the results. To deal with this issue, the company took the same approach currently used for hydro modeling and developed three levels of stochastic outages based on the 25th, 50th, and 75th percentile.

4.1 Weightings and Rankings for the Stochastic Series

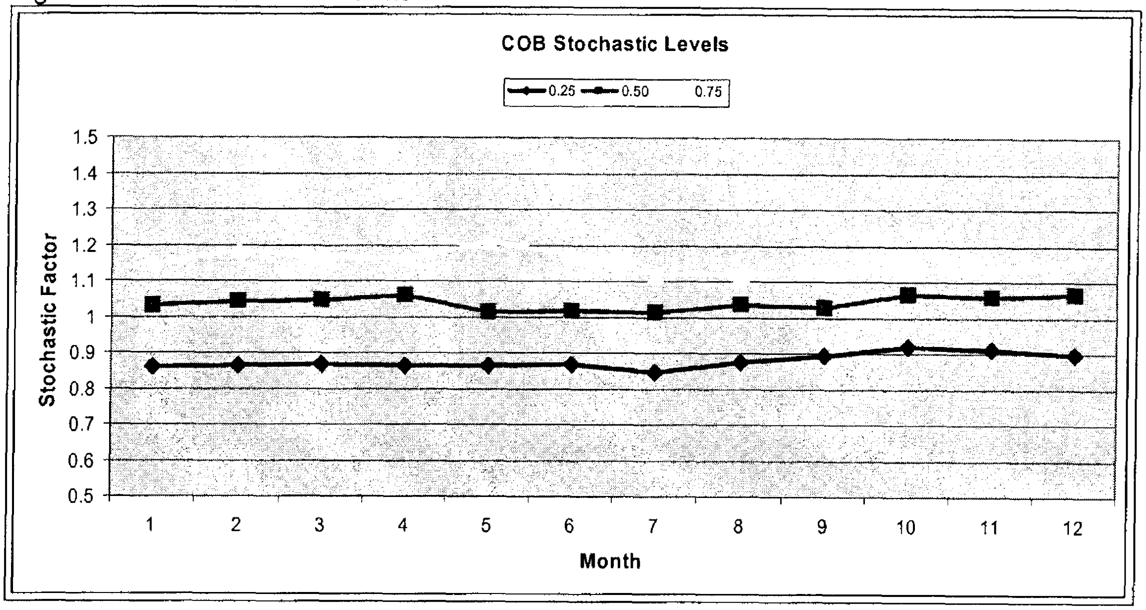
The key for condensing all the stochastic information into a set of twenty levels for the variables and three levels for the outages is appropriately weighting the iterations. For this purpose two sensitivity studies were prepared, one to weight the power cost variables and another to weight the outages. Utilizing economic concept of elasticity, the variable study calculated the impact on net power costs due a one percent change in the underlying variable. Table 4 presents a summary of these weightings.

Table 4. Net Power Cost Variable Weightings

NPC Variable	Elasticities	weights
NG East	0.17	4.05%
NG West	0.01	0.18%
Hydro West	-0.26	-6.11%
Hydro MidC	-0.13	-3.12%
Hydro East	-0.03	-0.75%
Price COB	-0.18	-4.30%
Price MidC	0.32	7.54%
Price 4C	-0.34	-8.08%
Price PV	0.28	6.63%
Load CA	0.07	1.62%
Load ID	0.26	6.32%
Load OR	1.13	26.99%
Load UT	1.88	45.01%
Load WA	0.38	9.09%
Load WY	0.62	14.92%
Total	4.18	100.00%

Figure 10 presents three of the stochastic levels, the 25th, 50th and 75th, developed from the weightings presented in Table 4 for the California-Oregon Border power prices.

Figure 10. COB Stochastic Levels



The thermal outage rankings are based on the weightings presented in Table 5. In the case of the thermal outage study, the percentages are calculated from the impact on net power costs by simply removing a unit from the available resource portfolio.

Table 5. Net Power Cost Thermal Outage Weightings

Unit	% weightings
Blundel	0.24%
Carbon1	0.90%
Carbon2	1.53%
Cholla4	5.80%
Colstrip3	0.96%
Colstrip4	1.12%
Craig1	1.32%
Craig2	1.31%
CurrantCreek	2.21%
DaveJohnston1	1.60%
DaveJohnston2	1.67%
DaveJohnston3	3.31%
DaveJohnston4	4.87%
Gadsby1	0.03%
Gadsby2	0.03%
Gadsby3	0.07%
Gadsby4	0.02%
Gadsby5	0.03%
Gadsby6	0.03%
Hayden1	0.63%
Hayden2	0.47%
Hermiston1	3.25%
Hermiston2	3.16%
Hunter1	5.91%
Hunter2	3.73%
Hunter3	7.27%
Huntington1	6.88%
Huntington2	6.88%
JimBridger1	4.99%
JimBridger2	4.93%
JimBridger3	5.00%
JimBridger4	4.86%
LittleMountain	0.29%
Naughton1	2.24%
Naughton2	2.90%
Naughton3	4.66%
WestValley1	0.08%
WestValley2	0.07%
WestValley3	0.08%
WestValley4	0.08%
WestValley5	0.08%
Wyodak	4.50%

In the end, the methodology provides twenty stochastic levels as a function of the shocks generated for natural gas and power prices, hydro generation and retail loads. Each stochastic level is run three times, once with each of the 25^{th}, 50th and 75^{th} percentiles of forced outages. The sixty GRID runs constitute the stochastic power cost study.

5.0 GRID Stochastic Results

Provided in Table 6 is the summary statistics for the final set of stochastic GRID runs. The base NPC for the present study is $838M, which is the $839M approved NPC in the 2006 General Rate Case run at the median hydro level. The overall result of the study shows that under conditions of uncertainty, the company's expected NPC increases by approximately $6.4 million. The distributional character shows some degree of skewness, but no significant leptokurtosis. Presented in Table 6 is both the with and without the company's natural gas hedge position. The difference in median estimates is of interest, and an item that the stochastic study highlights.

Table 6. Summary Statistics for 60 Stochastic GRID runs

	NPC ($)	delta from Base	NPC ($) sans Gas Position	delta from Base
mean =	**$ 844,432,610**	**$ 6,383,626**	**$ 920,875,469**	**$ 6,386,040**
median =	833,224,091		901,154,939	
max =	1,207,224,355	369,175,370	1,289,349,201	374,859,773
min =	584,664,131	(253,384,853)	633,562,293	(280,927,135)
SD =	140,117,205		144,836,083	
SE =	18,089,053		18,698,258	
skew =	0.5291		0.4350	
kurt =	0.2984		0.2574	
N =	60		60	

The gas position is the company's major hedging strategy for natural gas price volatility, and to the extent of the correlation with power markets, electricity price volatility. The variability in the gas hedge value is under the same pressures as the rest of the natural gas price variables, except that it acts as a benefit during periods of adverse price movements and otherwise as a cost stabilizer. This benefit is significant in that in comparing the two cases, the difference in the mean and median is approximately $11 million when the gas hedge is included, without the hedge the mean median spread nearly doubles to $20 million. Part 3 of Appendix A provides the full sixty GRID runs.

The final distribution is presented in Figure 11. The histogram divides the whole range of $622 million into ten bins. Evident is the skewness of the distribution with 5% extreme values on the right tail. Under uncertainty, the company's power costs are susceptible to extreme cost impacts.

Figure 11. Net Power Cost Distribution

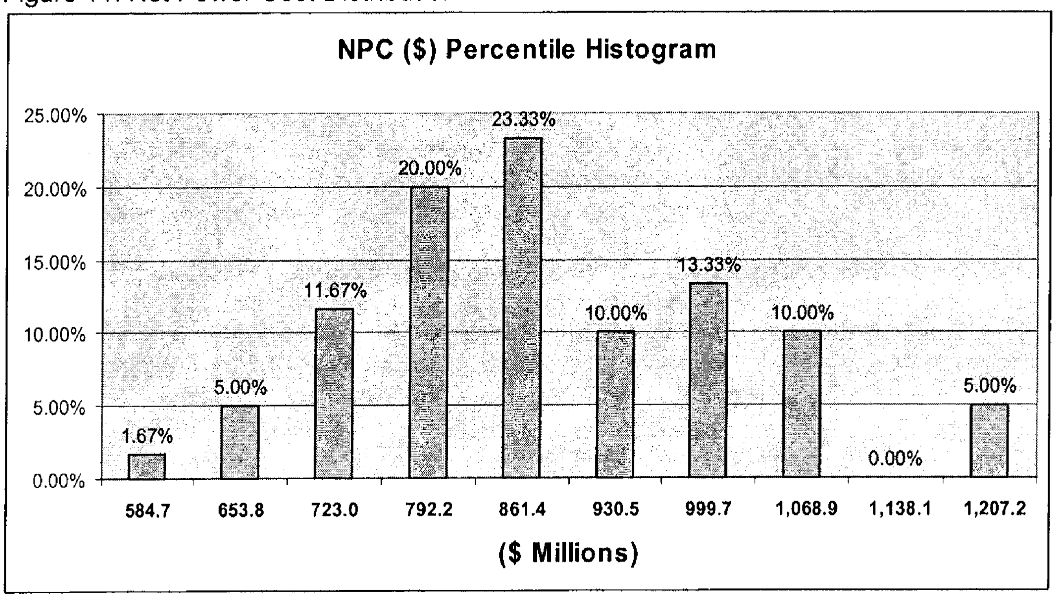
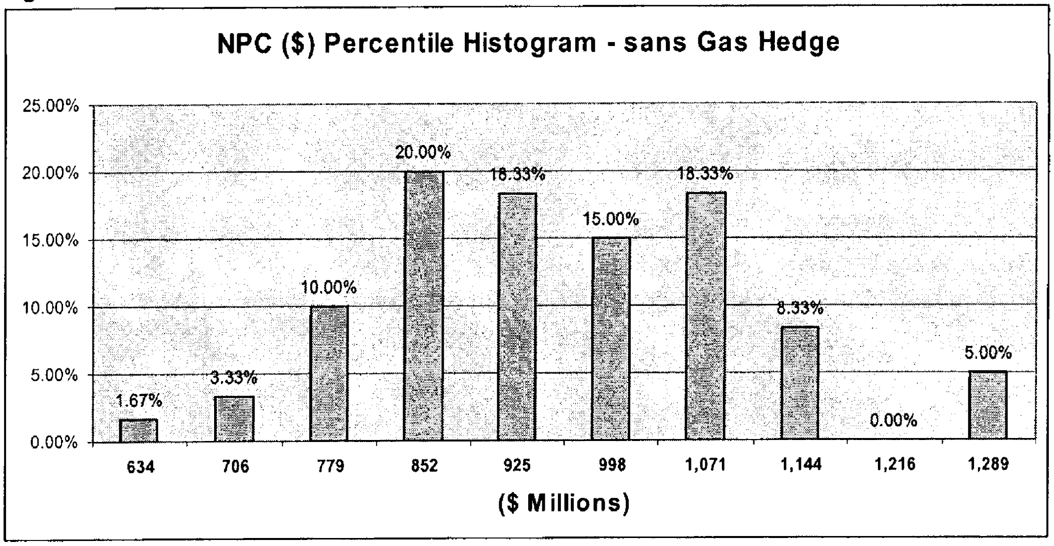


Figure 12 shows the same analysis as before, but excluding the company's gas position. Again, the extreme values are present, though the distribution has shifted, which is confirms the findings of summary statistics presented in Table 6.

Figure 12. Net Power Cost Distribution



6.0 Feasibility of Power Cost Modeling

There are three notable obstacles to making stochastic power cost modeling feasible. First, the man-hours required to perform the study with the current technological constraints is a significant hurdle. Second, the company's current power cost model is not configured to easily facilitate this sort of study. Rearchitecturing the GRID model would be overly costly. And finally, finding the technical staff to do this type of modeling.

The current study required close to 400 hours of work. Repeating the study would lessen this requirement by some degree – building certain spreadsheet tools and original thinking would not have to be repeated. However, with new data sets as the time rolls along and changing energy markets there will always be a need to do original thinking and some first of a kind modeling.

Under GRID's current configuration there is no mass storage capability for either inputs or outputs as would be required to house the stochastic engine within GRID, not to mention that GRID does not have a stochastic engine. The current study finesses the problem by utilizing the PaR model's stochastic capabilities to perform the front-end of the study and then push the inputs through GRID. Unfortunately the GRID and PaR inputs, though conceptually based on similar principles, are not identical. PaR stochastic input does not feed directly into the GRID model. Rather the stochastic factors generated by PaR have to be applied to the GRID inputs. Further, if taken in their rawest form, the PaR factors would require producing 100 GRID data sets and 1000 GRID runs. For this to be feasible within GRID itself would require a significant rearchitecture of the GRID model and a significant upgrade in its database capabilities (in fact when the PaR model makes a run it discards most of the output, so that it does not overfill its database).

The requirements of personnel are also significant. Personnel with both formal and work experience in econometrics do not occur in great numbers in the labor force. The technical expertise required to clean, analyze and verify the stochastic portion of the study is a minimum of graduate level econometrics

The most significant of the three is the current GRID configuration. This would almost have to be done to make stochastic modeling feasible. This would also reduce the man-hour requirements by removing the need to laboriously input data sets into GRID.

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[1] This is due two factors. First, power and natural gas markets have extensive and highly liquid forward markets (especially in the near term). This supplies power and natural gas trading concerns with a breadth of information for forming, or reforming, expectations about the duration and severity of market shocks. Also, because of the existence of liquid forward markets, market participants can efficiently mitigate market contingencies. Secondly, and this is especially true with respect to power markets, but also to a lesser degree in gas markets, because of the nature of the commodities and technology used to produce and deliver them, market participants are under increased pressure during periods of disequilibrium to wring further efficiencies out of markets and producers own systems.

APPENDIX A

Part 1 – Correlations

LT Correlations	L - Idaho	L - Utah	L - Washing	L - West Ma	L - Wyomin	P - 4C	P - COB	P - MidC	P - PV	P - NG E	P - NG W	H - MidC	H - PACE	H - PACW
L - Idaho	1	0.2682	0.1659	0.1737	0.1217	0.0405	0.0284	0.0334	0.0245	0.0519	0.0541	0.0179	-0.0782	0.0299
L - Utah	0.2682	1	0.2239	0.2673	0.2640	0.2434	0.1751	0.1569	0.2266	-0.0196	0.0367	0.0660	-0.0497	0.1023
L - Washington	0.1659	0.2239	1	0.5952	0.1868	0.0993	0.1683	0.1602	0.0807	-0.0045	0.1281	0.0902	-0.0427	0.1910
L - West Main	0.1737	0.2673	0.5952	1	0.1853	0.1531	0.2204	0.2270	0.1367	-0.0049	0.0971	0.0951	-0.0450	0.1798
L - Wyoming	0.1217	0.2640	0.1868	0.1853	1	0.0779	0.0783	0.0673	0.0669	0.0097	0.0307	-0.0002	-0.0292	0.0334
P - 4C	0.0405	0.2434	0.0993	0.1531	0.0779	1	0.7103	0.5996	0.8685	0.1067	0.2588	-0.0453	0.0002	0.0255
P - COB	0.0284	0.1751	0.1683	0.2204	0.0783	0.7103	1	0.7707	0.7285	0.1012	0.2772	-0.0652	0.0007	0.0269
P - MidC	0.0334	0.1569	0.1602	0.2270	0.0673	0.5996	0.7707	1	0.6262	0.0579	0.2587	-0.0924	-0.0079	0.0231
P - PV	0.0245	0.2266	0.0807	0.1367	0.0669	0.8685	0.7285	0.6262	1	0.1155	0.2593	-0.0612	0.0136	0.0185
P - NG E	0.0519	-0.0196	-0.0045	-0.0049	0.0097	0.1067	0.1012	0.0579	0.1155	1	0.5012	0.0372	-0.0080	-0.0114
P - NG W	0.0541	0.0367	0.1281	0.0971	0.0307	0.2588	0.2772	0.2587	0.2593	0.5012	1	0.0733	-0.0358	0.0174
H - MidC	0.0179	0.0660	0.0902	0.0951	-0.0002	-0.0453	-0.0652	-0.0924	-0.0612	0.0372	0.0733	1	-0.0618	-0.0183
H - PACE	-0.0782	-0.0497	-0.0427	-0.0450	-0.0292	0.0002	0.0007	-0.0079	0.0136	-0.0080	-0.0358	-0.0618	1	0.0693
H - PACW	0.0299	0.1023	0.1910	0.1798	0.0334	0.0255	0.0269	0.0231	0.0185	-0.0114	0.0174	-0.0183	0.0693	1

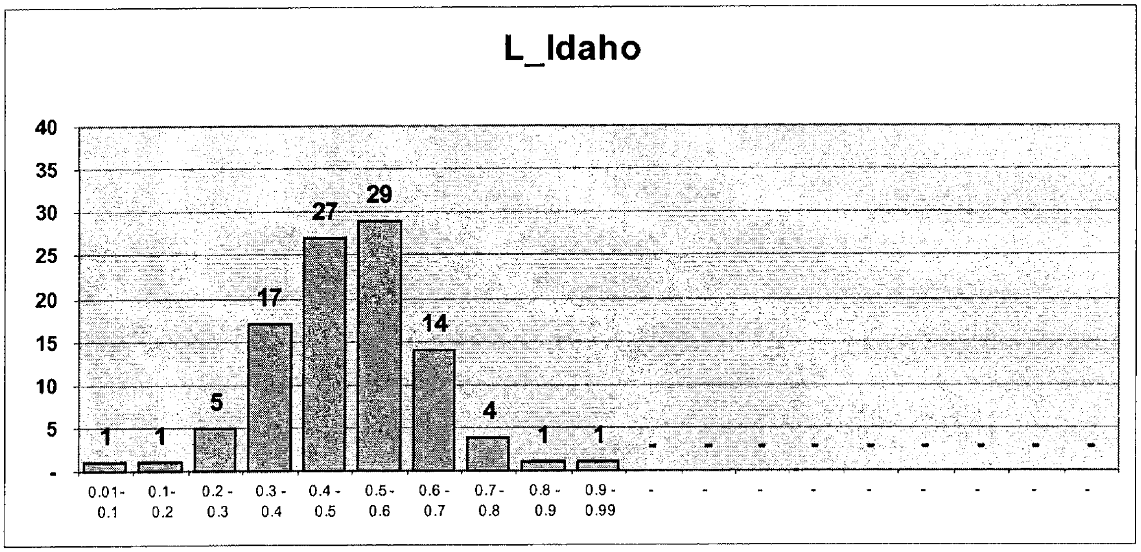
ST Correlations - Fall	L - Idaho	L - Utah	L - Washing	L - West Ma	L - Wyomin	P - 4C	P - COB	P - MidC	P - PV	P - NG E	P - NG W	H - MidC	H - PACE	H - PACW
L - Idaho	1	0.2524	0.1390	0.0308	0.1202	0.0975	0.0797	0.0450	0.0779	0.1926	0.1180	0.0499	-0.0813	-0.0276
L - Utah	0.2524	1	0.3164	0.3378	0.2621	0.1142	0.0452	0.0678	0.0598	-0.0644	-0.0767	0.1880	-0.0666	-0.0092
L - Washington	0.1390	0.3164	1	0.6550	0.2554	-0.0790	-0.0310	-0.0468	-0.1443	-0.0842	-0.0743	0.1998	0.0051	0.1148
L - West Main	0.0308	0.3378	0.6550	1	0.1953	-0.0177	-0.0732	-0.0316	-0.1190	-0.0973	-0.1609	0.1755	-0.0367	0.1376
L - Wyoming	0.1202	0.2621	0.2554	0.1953	1	0.1230	0.0757	0.1763	0.1134	-0.0672	-0.0922	0.0409	-0.0332	0.0216
P - 4C	0.0975	0.1142	-0.0790	-0.0177	0.1230	1	0.4192	0.6589	0.8438	0.1429	0.2232	0.0737	-0.1126	0.0029
P - COB	0.0797	0.0452	-0.0310	-0.0732	0.0757	0.4192	1	0.4085	0.4273	0.2132	0.2742	-0.0026	-0.1316	0.0335
P - MidC	0.0450	0.0678	-0.0468	-0.0316	0.1763	0.6589	0.4085	1	0.6778	0.1300	0.1469	-0.0293	-0.0415	0.0854
P - PV	0.0779	0.0598	-0.1443	-0.1190	0.1134	0.8438	0.4273	0.6778	1	0.1666	0.2573	0.0094	-0.0694	0.0107
P - NG E	0.1926	-0.0644	-0.0842	-0.0973	-0.0672	0.1429	0.2132	0.1300	0.1666	1	0.7278	-0.0326	0.0571	0.0274
P - NG W	0.1180	-0.0767	-0.0743	-0.1609	-0.0922	0.2232	0.2742	0.1469	0.2573	0.7278	1	-0.0015	0.0097	0.0442
H - MidC	0.0499	0.1880	0.1998	0.1755	0.0409	0.0737	-0.0026	-0.0293	0.0094	-0.0326	-0.0015	1	-0.0450	-0.0451
H - PACE	-0.0813	-0.0666	0.0051	-0.0367	-0.0332	-0.1126	-0.1316	-0.0415	-0.0694	0.0571	0.0097	-0.0450	1	0.1121
H - PACW	-0.0276	-0.0092	0.1148	0.1376	0.0216	0.0029	0.0335	0.0854	0.0107	0.0274	0.0442	-0.0451	0.1121	1

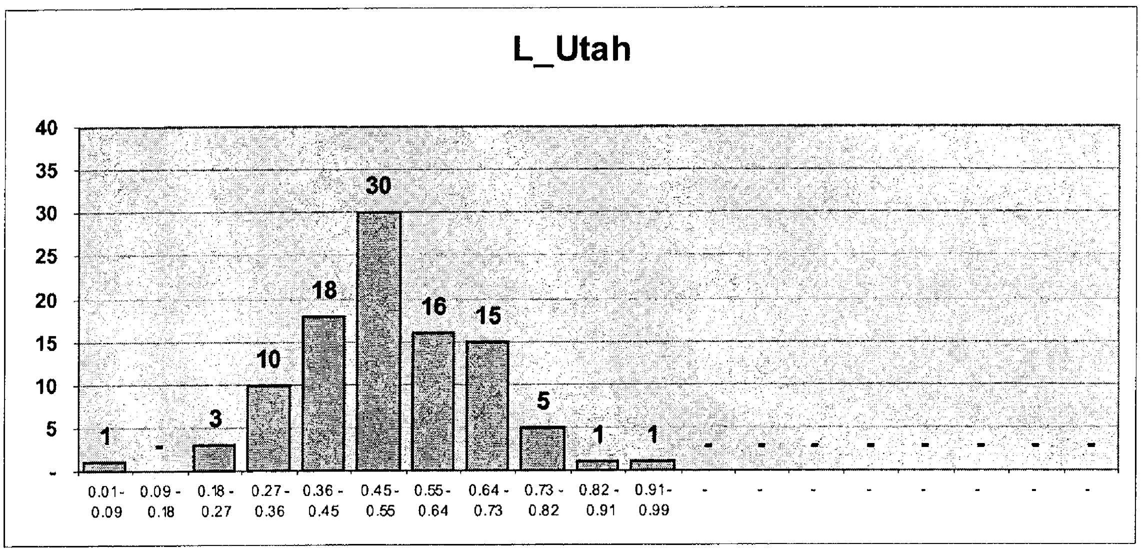
ST Correlations - Winter	L - Idaho	L - Utah	L - Washing	L - West Ma	L - Wyomin	P - 4C	P - COB	P - MidC	P - PV	P - NG E	P - NG W	H - MidC	H - PACE	H - PACW
L - Idaho	1	0.3281	0.2091	0.0301	0.1656	-0.0836	-0.0254	-0.0483	-0.0811	-0.1877	-0.1244	0.1070	-0.0693	0.0933
L - Utah	0.3281	1	0.4241	0.3289	0.3315	0.2120	0.1170	0.1685	0.1389	-0.0582	-0.0378	0.2446	-0.0402	0.2268
L - Washington	0.2091	0.4241	1	0.6382	0.2993	0.2013	0.0802	0.1403	0.1395	-0.0691	-0.0487	0.1506	-0.0125	0.2459
L - West Main	0.2816	0.4396	0.6125	1	0.2685	0.1401	0.1308	0.1014	0.0980	-0.1299	-0.0722	0.1302	0.0073	0.2747
L - Wyoming	0.1656	0.3315	0.2993	0.1902	1	0.0030	-0.0300	-0.0147	-0.0270	-0.1569	-0.1596	0.0679	-0.0646	0.0708
P - 4C	-0.0836	0.2120	0.2013	-0.0173	0.0030	1	0.5281	0.6988	0.7282	0.2712	0.2667	-0.0527	-0.0959	0.0799
P - COB	-0.0254	0.1170	0.0802	-0.0711	-0.0300	0.5281	1	0.5650	0.5027	0.3439	0.4392	-0.0943	-0.0538	0.0865
P - MidC	-0.0483	0.1685	0.1403	-0.0308	-0.0147	0.6988	0.5650	1	0.7234	0.2473	0.2781	-0.1113	-0.0566	0.0512
P - PV	-0.0811	0.1389	0.1395	-0.1159	-0.0270	0.7282	0.5027	0.7234	1	0.3310	0.3244	-0.0959	-0.1257	0.0321
P - NG E	-0.1877	-0.0582	-0.0691	-0.0948	-0.1569	0.2712	0.3439	0.2473	0.3310	1	0.7443	-0.0004	-0.0061	-0.0352
P - NG W	-0.1244	-0.0378	-0.0487	-0.1568	-0.1596	0.2667	0.4392	0.2781	0.3244	0.7443	1	-0.0675	-0.0038	0.0296
H - MidC	0.1070	0.2446	0.1506	0.1710	0.0679	-0.0527	-0.0943	-0.1113	-0.0959	-0.0004	-0.0675	1	-0.0502	-0.0058
H - PACE	-0.0693	-0.0402	-0.0125	-0.0356	-0.0646	-0.0959	-0.0538	-0.0566	-0.1257	-0.0061	-0.0038	-0.0502	1	0.0512
H - PACW	0.0933	0.2268	0.2459	0.1341	0.0708	0.0799	0.0865	0.0512	0.0321	-0.0352	0.0296	-0.0058	0.0512	1

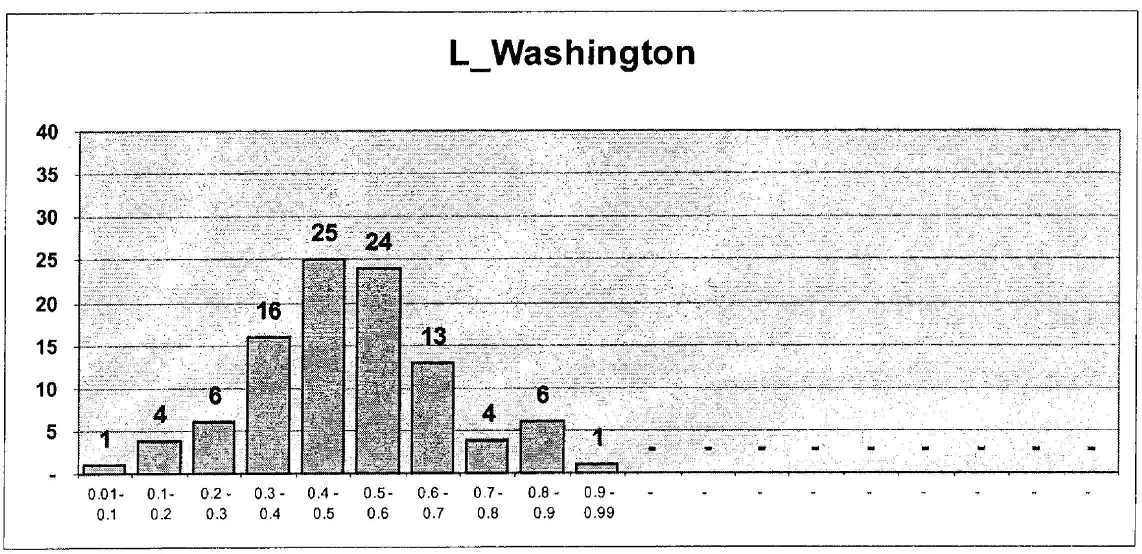
ST Correlations - Spring	L - Idaho	L - Utah	L - Washing	L - West Ma	L - Wyomin	P - 4C	P - COB	P - MidC	P - PV	P - NG E	P - NG W	H - MidC	H - PACE	H - PACW
L - Idaho	1	0.3035	0.0051	0.0335	0.0013	-0.0108	0.0002	0.0691	0.0266	-0.0045	0.1035	0.0717	-0.0871	0.0388
L - Utah	0.3035	1	0.0210	0.3689	0.1053	0.1646	0.0386	0.0627	0.2080	-0.1689	-0.1086	0.1730	0.0400	0.0241
L - Washington	0.0051	0.0210	1	0.7138	0.2012	-0.0118	0.0573	0.0035	-0.0270	-0.0966	0.0326	0.1396	-0.1401	0.1138
L - West Main	0.0915	0.1698	0.5534	1	0.2079	0.1046	0.0898	0.0876	0.1186	-0.0792	0.0265	0.1848	-0.1144	0.1397
L - Wyoming	0.0013	0.1053	0.2012	0.2131	1	-0.0337	-0.0063	0.0096	0.0047	-0.1015	-0.0240	0.0345	0.0854	-0.0542
P - 4C	-0.0108	0.1646	-0.0118	-0.0193	-0.0337	1	0.5587	0.4590	0.7867	0.0848	0.0253	0.0332	0.0518	-0.0881
P - COB	0.0002	0.0386	0.0573	-0.0802	-0.0063	0.5587	1	0.7699	0.4679	0.0337	0.0669	0.0321	-0.0390	0.0491
P - MidC	0.0691	0.0627	0.0035	-0.0344	0.0096	0.4590	0.7699	1	0.5404	-0.1314	-0.0591	-0.0259	-0.0372	0.0083
P - PV	0.0266	0.2080	-0.0270	-0.1296	0.0047	0.7867	0.4679	0.5404	1	0.1055	-0.0354	0.0670	-0.0383	-0.1219
P - NG E	-0.0045	-0.1689	-0.0966	-0.1061	-0.1015	0.0848	0.0337	-0.1314	0.1055	1	0.2806	-0.0636	-0.0033	0.0108
P - NG W	0.1035	-0.1086	0.0326	-0.1754	-0.0240	0.0253	0.0669	-0.0591	-0.0354	0.2806	1	-0.1282	-0.1552	0.0677
H - MidC	0.0717	0.1730	0.1396	0.1909	0.0345	0.0332	0.0321	-0.0259	0.0670	-0.0636	-0.1282	1	-0.1611	-0.0933
H - PACE	-0.0871	0.0400	-0.1401	-0.0404	0.0854	0.0518	-0.0390	-0.0372	-0.0383	-0.0033	-0.1552	-0.1611	1	-0.0112
H - PACW	0.0388	0.0241	0.1138	0.1501	-0.0542	-0.0881	0.0491	0.0083	-0.1219	0.0108	0.0677	-0.0933	-0.0112	1

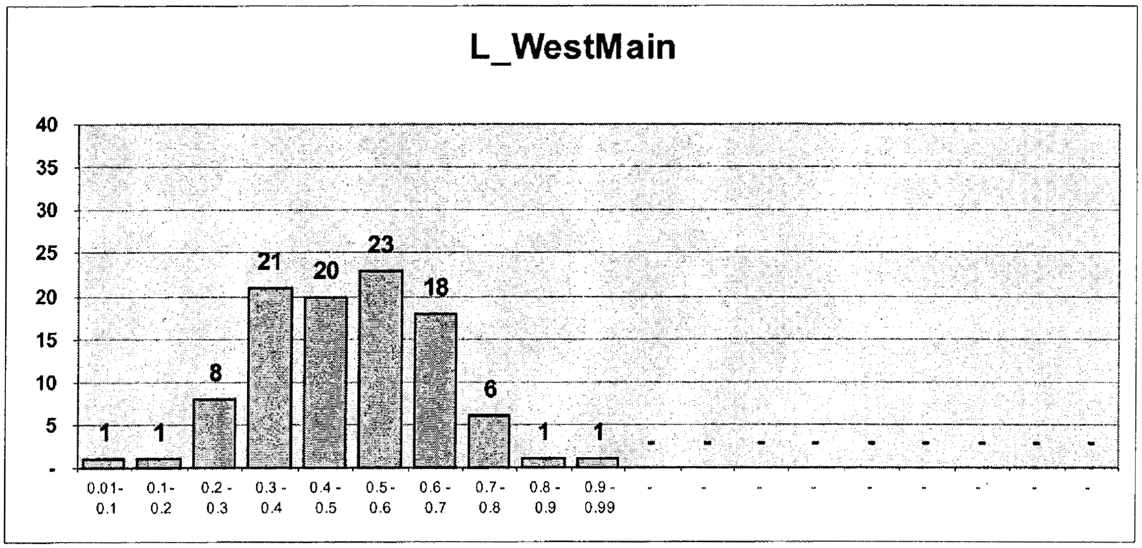
ST Correlations - Summer	L - Idaho	L - Utah	L - Washing	L - West Ma	L - Wyomin	P - 4C	P - COB	P - MidC	P - PV	P - NG E	P - NG W	H - MidC	H - PACE	H - PACW
L - Idaho	1	0.2222	0.2100	0.0288	0.1268	0.0904	0.0691	0.1040	0.1136	0.0784	0.0237	0.0595	-0.1295	0.0471
L - Utah	0.2222	1	0.2190	0.3212	0.3282	0.2512	0.1600	0.1164	0.2060	-0.0797	-0.0778	-0.1137	-0.0242	0.1327
L - Washington	0.2100	0.2190	1	0.6186	0.0784	0.0886	0.1249	0.1018	0.0823	0.0032	0.0102	0.0207	-0.0674	0.1429
L - West Main	0.1502	0.2242	0.6110	1	0.0531	0.1565	0.1775	0.1809	0.1362	-0.0369	-0.0483	-0.0302	-0.0490	0.1190
L - Wyoming	0.1268	0.3282	0.0784	0.1853	1	0.0787	-0.0641	-0.0857	0.0497	-0.0799	-0.0697	-0.0569	-0.0062	0.0382
P - 4C	0.0904	0.2512	0.0886	-0.0166	0.0787	1	0.6141	0.6088	0.7985	0.1002	0.1146	-0.1324	-0.0047	-0.1189
P - COB	0.0691	0.1600	0.1249	-0.0705	-0.0641	0.6141	1	0.7045	0.6392	0.0646	0.1021	-0.1533	-0.0403	-0.0750
P - MidC	0.1040	0.1164	0.1018	-0.0298	-0.0857	0.6088	0.7045	1	0.6057	0.0015	0.0116	-0.1566	-0.0510	-0.0982
P - PV	0.1136	0.2060	0.0823	-0.1123	0.0497	0.7985	0.6392	0.6057	1	0.0882	0.1098	-0.1078	0.0271	-0.1057
P - NG E	0.0784	-0.0797	0.0032	-0.0919	-0.0799	0.1002	0.0646	0.0015	0.0882	1	0.7909	-0.0064	-0.0130	-0.0355
P - NG W	0.0237	-0.0778	0.0102	-0.1520	-0.0697	0.1146	0.1021	0.0116	0.1098	0.7909	1	-0.0053	-0.0179	0.0186
H - MidC	0.0595	-0.1137	0.0207	0.1649	-0.0569	-0.1324	-0.1533	-0.1566	-0.1078	-0.0064	-0.0053	1	0.0914	0.0206
H - PACE	-0.1295	-0.0242	-0.0674	-0.0360	-0.0062	-0.0047	-0.0403	-0.0510	0.0271	-0.0130	-0.0179	0.0914	1	0.0539
H - PACW	0.0471	0.1327	0.1429	0.1303	0.0382	-0.1189	-0.0750	-0.0982	-0.1057	-0.0355	0.0186	0.0206	0.0539	1

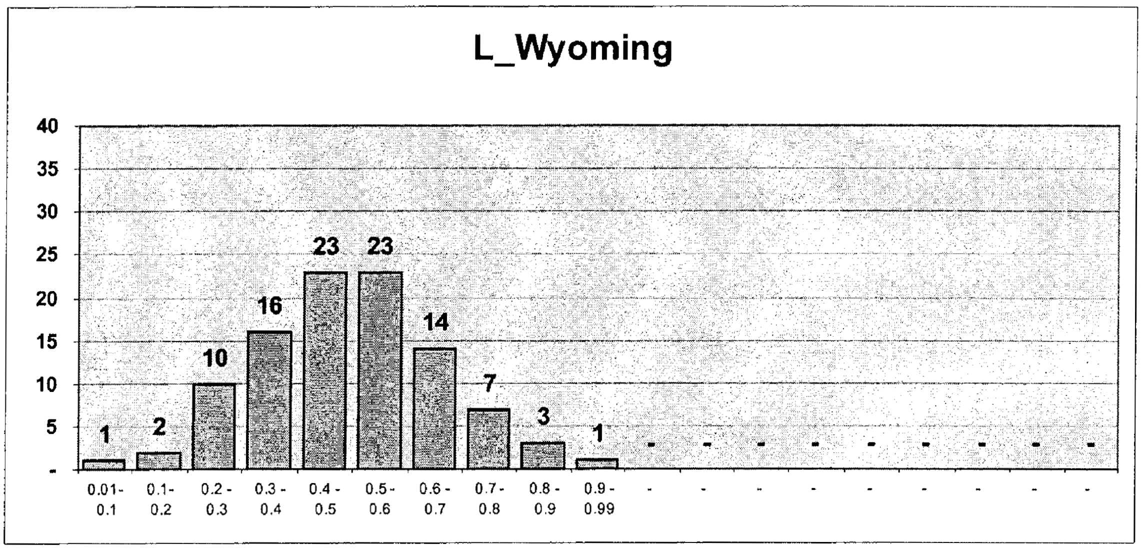
Part 2 – Stochastic Shock Distributions

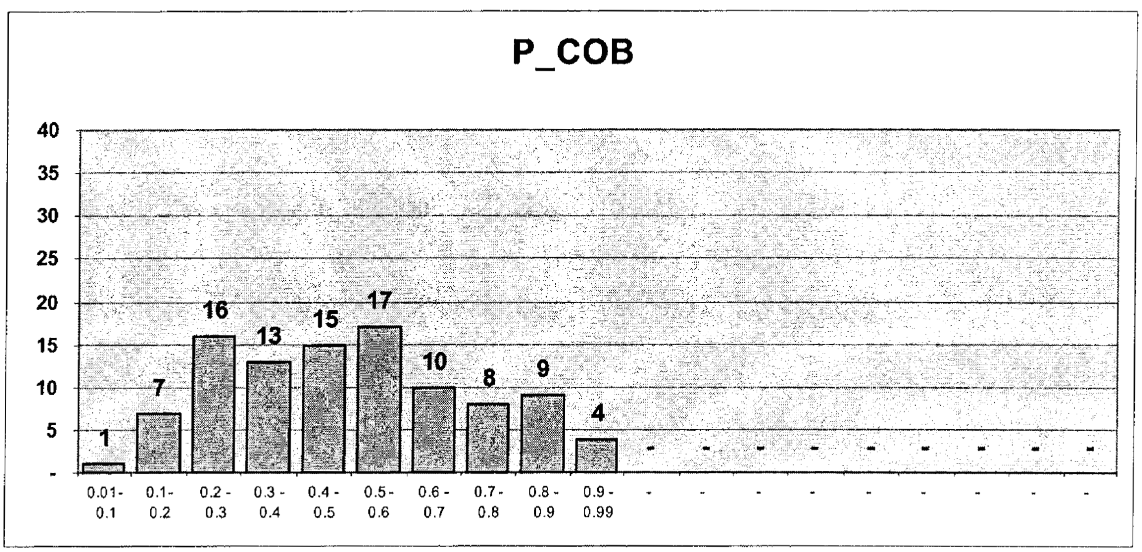


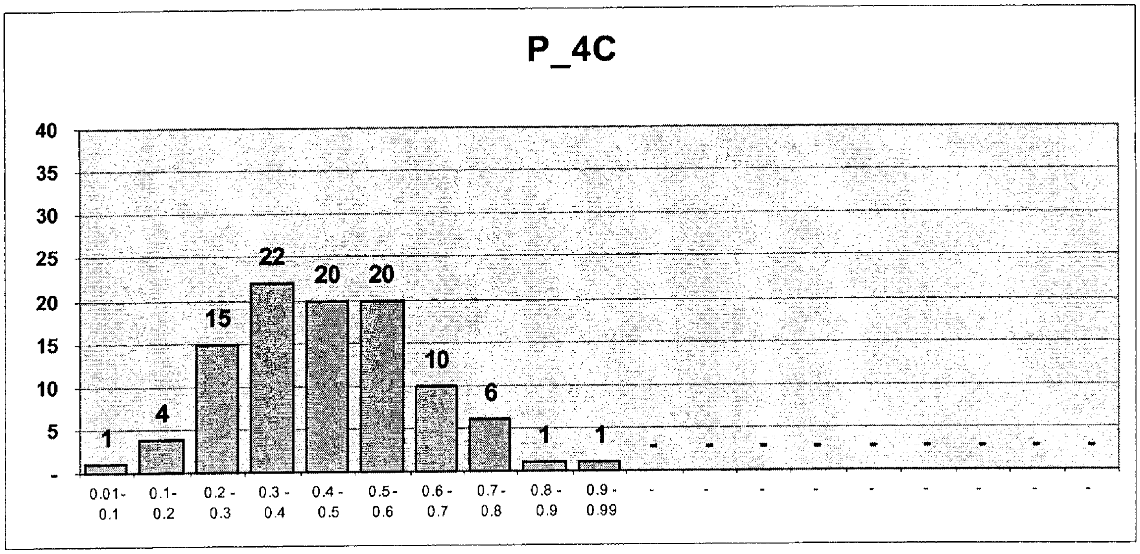


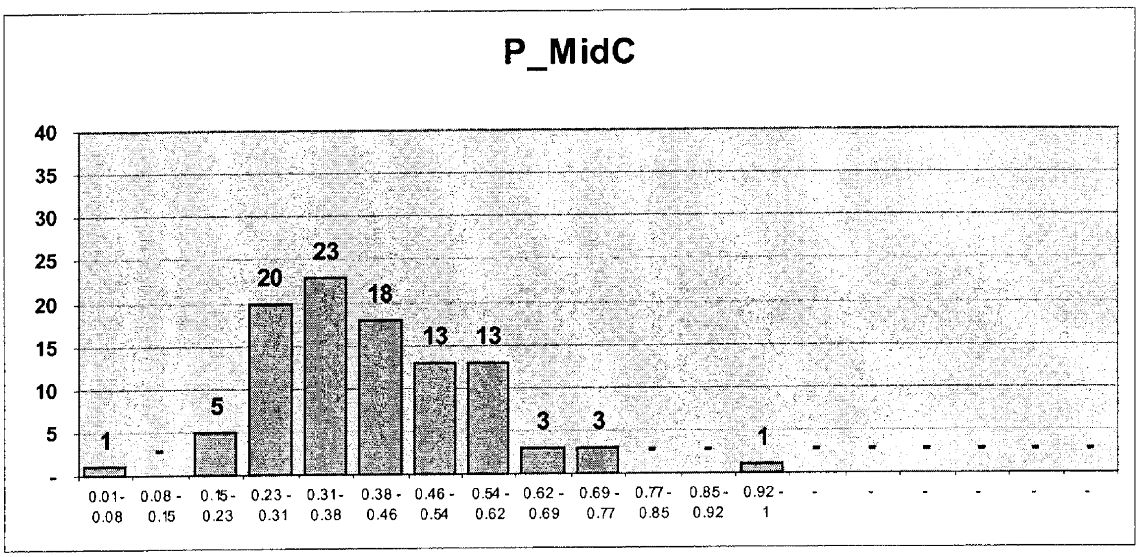


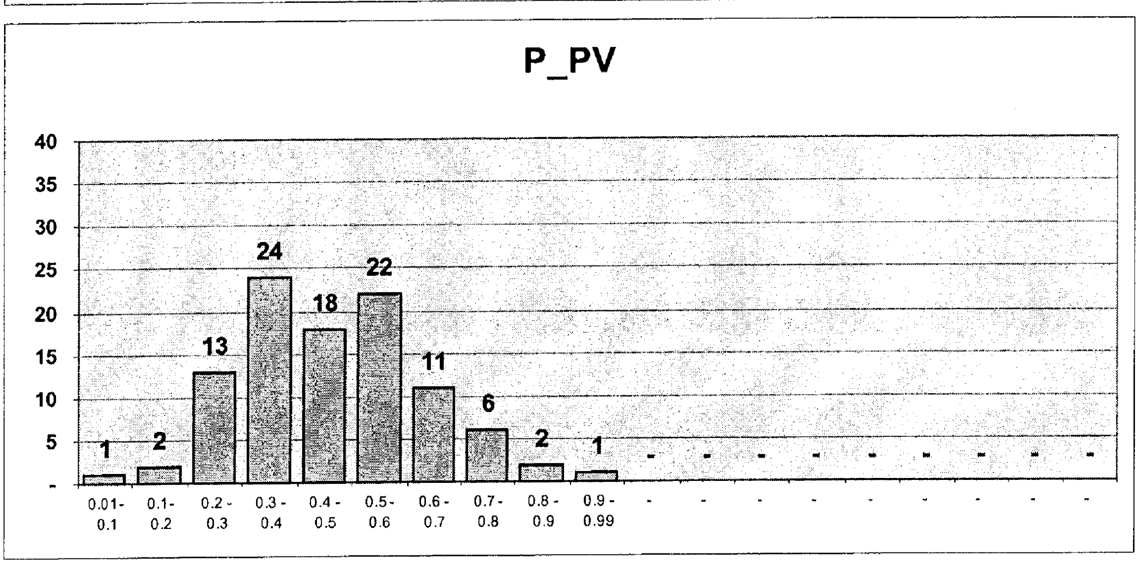

L_WestMain
40
35
30
25
20
15
10
5
-
1 1 8 21 20 23 18 6 1 1
0.01- 0.1
0.1- 0.2
0.2 - 0.3
0.3 - 0.4
0.4 - 0.5
0.5 - 0.6
0.6 - 0.7
0.7 - 0.8
0.8 - 0.9
0.9 - 0.99

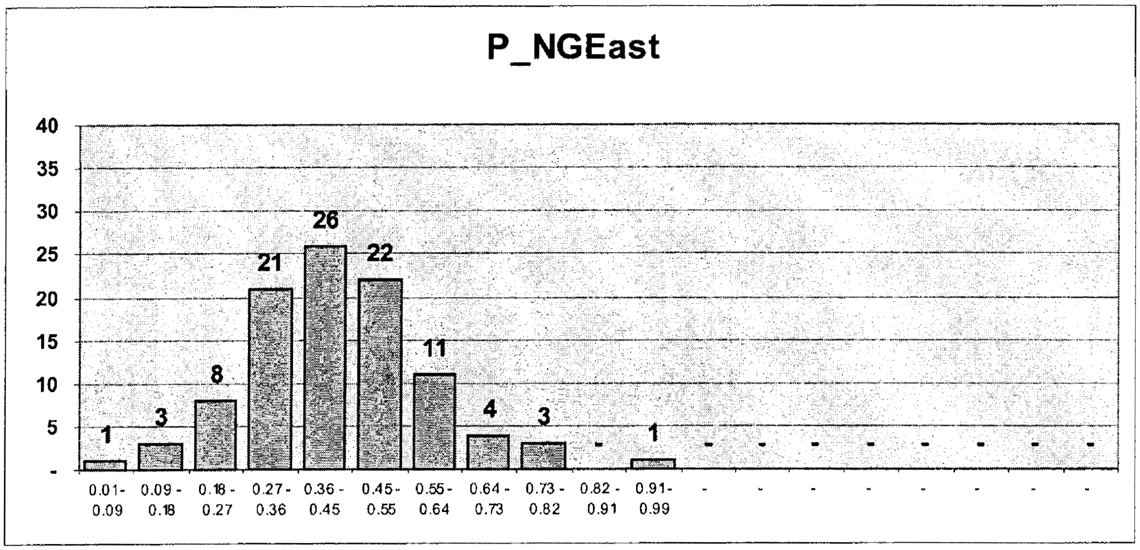

L_Wyoming
40
35
30
25
20
15
10
5
-
1 2 10 16 23 23 14 7 3 1
0.01- 0.1
0.1- 0.2
0.2 - 0.3
0.3 - 0.4
0.4 - 0.5
0.5 - 0.6
0.6 - 0.7
0.7 - 0.8
0.8 - 0.9
0.9 - 0.99

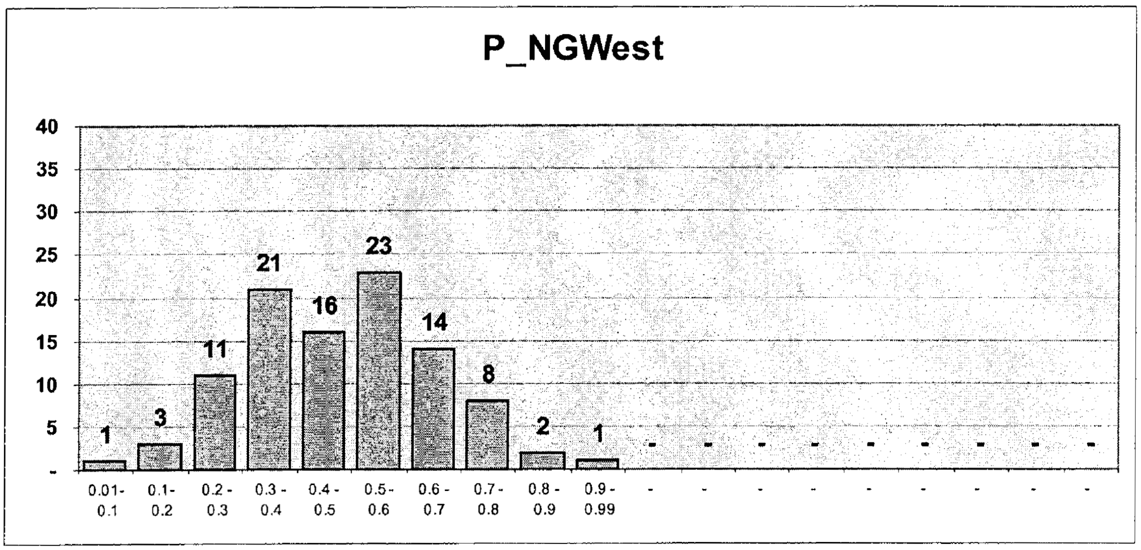

P_COB
40
35
30
25
20
15
10
5
-
1 7 16 13 15 17 10 8 9 4
0.01- 0.1
0.1- 0.2
0.2 - 0.3
0.3 - 0.4
0.4 - 0.5
0.5 - 0.6
0.6 - 0.7
0.7- 0.8
0.8 - 0.9
0.9 - 0.99

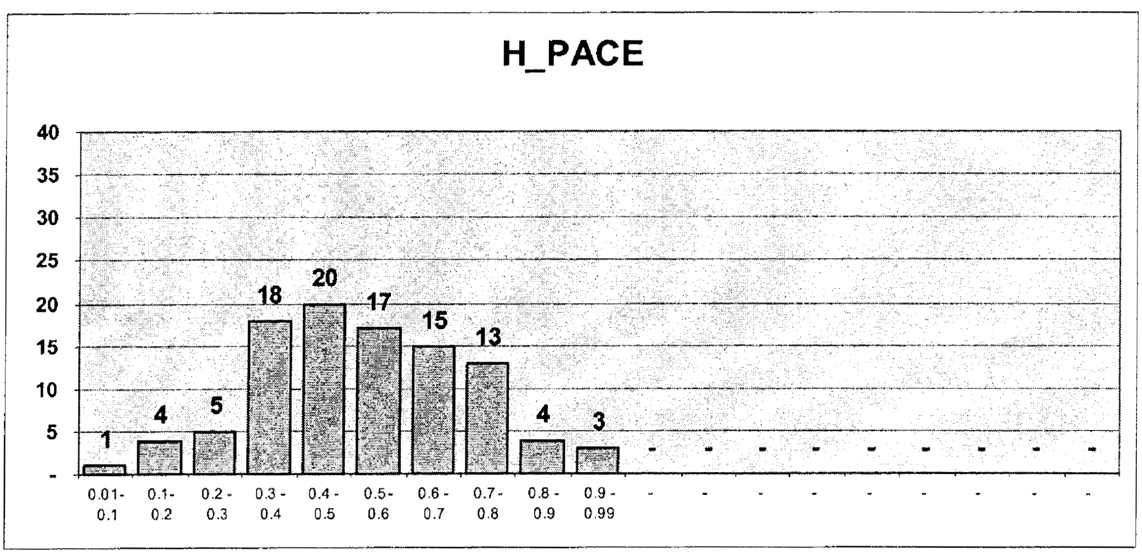

P_4C
40
35
30
25
20
15
10
5
-
1
4
15
22
20
20
10
6
1
1
0.01-0.1
0.1-0.2
0.2-0.3
0.3-0.4
0.4-0.5
0.5-0.6
0.6-0.7
0.7-0.8
0.8-0.9
0.9-0.99

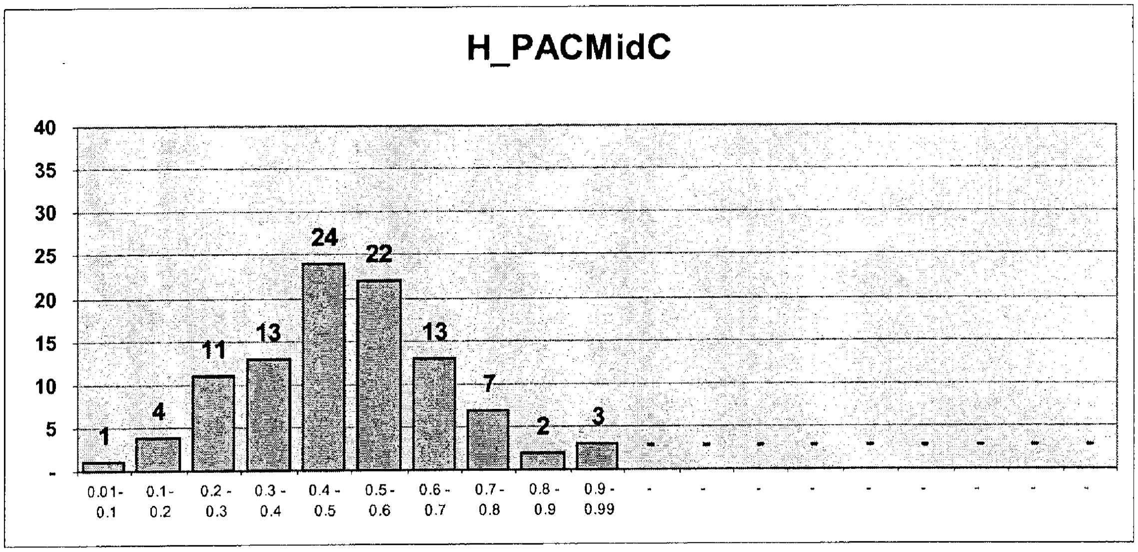

P_MidC
40
35
30
25
20
15
10
5
-
1
5
20
23
18
13
13
3
3
1
0.01-0.08
0.08-0.15
0.15-0.23
0.23-0.31
0.31-0.38
0.38-0.46
0.46-0.54
0.54-0.62
0.62-0.69
0.69-0.77
0.77-0.85
0.85-0.92
0.92-1

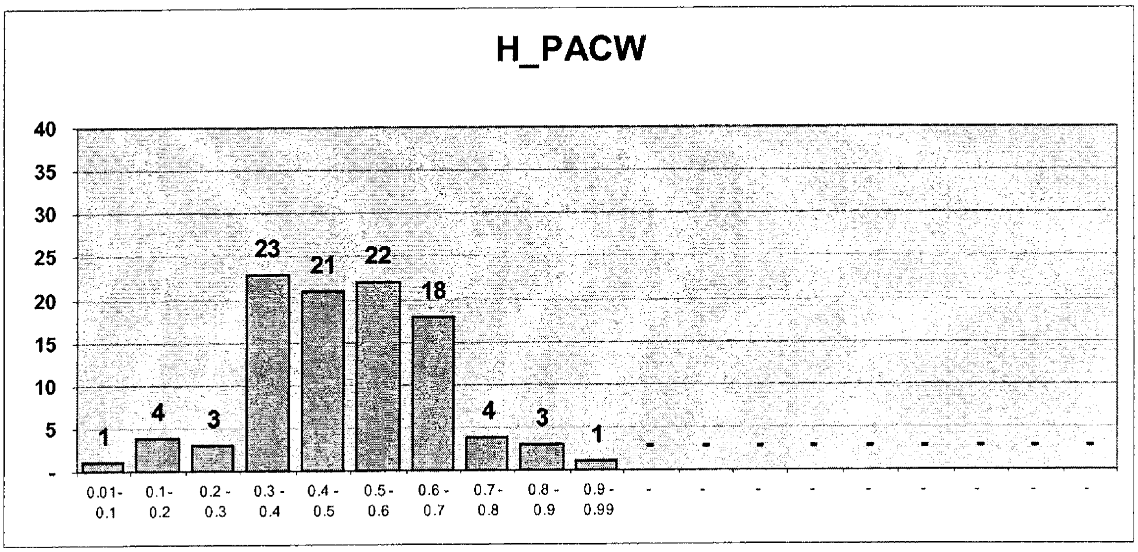

P_PV
40
35
30
25
20
15
10
5
-
1
2
13
24
18
22
11
6
2
1
0.01-0.1
0.1-0.2
0.2-0.3
0.3-0.4
0.4-0.5
0.5-0.6
0.6-0.7
0.7-0.8
0.8-0.9
0.9-0.99


P_NGEast
40
35
30
25
20
15
10
5
-
1
3
8
21
26
22
11
4
3
1
0.01-0.09
0.09-0.18
0.18-0.27
0.27-0.36
0.36-0.45
0.45-0.55
0.55-0.64
0.64-0.73
0.73-0.82
0.82-0.91
0.91-0.99


P_NGWest
40
35
30
25
20
15
10
5
-
1
3
11
21
16
23
14
8
2
1
0.01-0.1
0.1-0.2
0.2-0.3
0.3-0.4
0.4-0.5
0.5-0.6
0.6-0.7
0.7-0.8
0.8-0.9
0.9-0.99


H_PACE
40
35
30
25
20
15
10
5
-
1
4
5
18
20
17
15
13
4
3
0.01-0.1
0.1-0.2
0.2-0.3
0.3-0.4
0.4-0.5
0.5-0.6
0.6-0.7
0.7-0.8
0.8-0.9
0.9-0.99


H_PACMidC
40
35
30
25
20
15
10
5
-
1
4
11
13
24
22
13
7
2
3
0.01- 0.1
0.1- 0.2
0.2 - 0.3
0.3 - 0.4
0.4 - 0.5
0.5 - 0.6
0.6 - 0.7
0.7 - 0.8
0.8 - 0.9
0.9 - 0.99


H_PACW
40
35
30
25
20
15
10
5
-
1
4
3
23
21
22
18
4
3
1
0.01- 0.1
0.1- 0.2
0.2 - 0.3
0.3 - 0.4
0.4 - 0.5
0.5 - 0.6
0.6 - 0.7
0.7 - 0.8
0.8 - 0.9
0.9 - 0.99

Part 3 – GRID Stochastic Runs

Stochastic NPC Summary				E[Impact ($)]			E[Impact ($)]
		Base NPC (50EL) =	**$ 838,048,984**	**$ 6,383,626**	(76,440,444)	**$ 914,489,429**	**$ 6,386,040**
NPC Rank by Total Cost (low to high)	Iteration	CumDist (%)	NPC ($) (a)	delta from Base (b)	Gas Position (c)	NPC ($) sans Gas Position (d)	delta from Base (b)
1	1	1.154%	584,664,131	(253,384,853)	(48,898,163)	633,562,293	(280,927,135)
2	2	2.334%	598,001,290	(240,047,695)	(48,898,163)	646,899,452	(267,589,976)
3	3	3.525%	603,298,119	(234,750,865)	(48,898,163)	652,196,282	(262,293,147)
4	7	4.815%	653,644,898	(184,404,086)	(94,069,563)	747,714,462	(166,774,967)
5	4	6.130%	666,345,964	(171,703,020)	(69,369,137)	735,715,101	(178,774,327)
6	8	7.457%	672,201,139	(165,847,846)	(94,069,563)	766,270,702	(148,218,727)
7	9	8.788%	674,522,041	(163,526,943)	(94,069,563)	768,591,604	(145,897,824)
8	5	10.131%	680,443,662	(157,605,323)	(69,369,137)	749,812,799	(164,676,630)
9	6	11.489%	688,007,371	(150,041,614)	(69,369,137)	757,376,508	(157,112,921)
10	13	12.869%	698,976,601	(139,072,384)	(90,083,042)	789,059,643	(125,429,786)
11	14	14.284%	716,929,728	(121,119,256)	(90,083,042)	807,012,770	(107,476,658)
12	15	15.714%	724,701,722	(113,347,262)	(90,083,042)	814,784,764	(99,704,664)
13	10	17.169%	737,183,356	(100,865,628)	(50,261,152)	787,444,509	(127,044,920)
14	11	18.652%	751,051,051	(86,997,933)	(50,261,152)	801,312,204	(113,177,225)
15	22	20.143%	755,737,117	(82,311,867)	(78,689,386)	834,426,503	(80,062,926)
16	12	21.636%	756,598,665	(81,450,319)	(50,261,152)	806,859,817	(107,629,611)
17	16	23.133%	758,197,348	(79,851,636)	(66,279,916)	824,477,264	(90,012,165)
18	23	24.652%	769,531,926	(68,517,058)	(78,689,386)	848,221,312	(66,268,117)
19	17	26.179%	773,579,020	(64,469,965)	(66,279,916)	839,858,935	(74,630,494)
20	24	27.710%	775,702,239	(62,346,745)	(78,689,386)	854,391,625	(60,097,804)
21	19	29.245%	777,855,516	(60,193,469)	(61,817,035)	839,672,551	(74,816,878)
22	18	30.791%	783,201,215	(54,847,769)	(66,279,916)	849,481,130	(65,008,298)
23	28	32.339%	784,353,034	(53,695,950)	(81,879,519)	866,232,553	(48,256,876)
24	20	33.909%	795,558,593	(42,490,392)	(61,817,035)	857,375,628	(57,113,801)
25	21	35.488%	800,180,515	(37,868,469)	(61,817,035)	861,997,550	(52,491,879)
26	29	37.071%	801,968,759	(36,080,225)	(81,879,519)	883,848,278	(30,641,151)
27	30	38.660%	804,980,328	(33,068,656)	(81,879,519)	886,859,847	(27,629,582)
28	25	40.281%	821,201,320	(16,847,664)	(53,460,760)	874,662,080	(39,827,348)
29	37	41.910%	825,302,311	(12,746,673)	(124,017,613)	949,319,924	34,830,495
30	34	43.549%	830,351,940	(7,697,044)	(79,668,034)	910,019,974	(4,469,455)
31	26	45.199%	836,096,241	(1,952,743)	(53,460,760)	889,557,002	(24,932,427)
32	27	46.854%	838,829,143	780,159	(53,460,760)	892,289,903	(22,199,526)
33	35	48.525%	846,316,681	8,267,697	(79,668,034)	925,984,716	11,495,287
34	38	50.198%	847,866,342	9,817,358	(124,017,613)	971,883,954	57,394,526
35	31	51.877%	850,541,366	12,492,382	(67,319,149)	917,860,515	3,371,087
36	39	53.561%	853,195,330	15,146,346	(124,017,613)	977,212,942	62,723,514
37	36	55.252%	856,694,860	18,645,876	(79,668,034)	936,362,894	21,873,466
38	32	56.971%	870,876,745	32,827,761	(67,319,149)	938,195,895	23,706,466
39	33	58.702%	877,340,104	39,291,120	(67,319,149)	944,659,253	30,169,824
40	40	60.447%	884,019,864	45,970,880	(93,490,479)	977,510,343	63,020,914
41	41	62.225%	900,635,063	62,586,079	(93,490,479)	994,125,542	79,636,113
42	42	64.021%	910,135,093	72,086,108	(93,490,479)	1,003,625,572	89,136,143
43	49	65.846%	924,574,397	86,525,413	(97,096,473)	1,021,670,870	107,181,442
44	46	67.690%	934,154,317	96,105,333	(65,555,226)	999,709,543	85,220,114
45	43	69.542%	938,351,850	100,302,866	(72,823,523)	1,011,175,373	96,685,944
46	50	71.399%	941,156,571	103,107,587	(97,096,473)	1,038,253,044	123,763,615
47	51	73.270%	947,844,387	109,795,403	(97,096,473)	1,044,940,860	130,451,431
48	47	75.143%	949,228,508	111,179,524	(65,555,226)	1,014,783,734	100,294,306
49	48	77.032%	957,044,954	118,995,969	(65,555,226)	1,022,600,180	108,110,751
50	44	78.923%	957,943,070	119,894,085	(72,823,523)	1,030,766,592	116,277,164
51	45	80.834%	968,240,018	130,191,034	(72,823,523)	1,041,063,541	126,574,112
52	55	82.814%	1,003,032,017	164,983,033	(94,853,501)	1,097,885,519	183,396,090
53	52	84.805%	1,008,886,519	170,837,535	(57,100,655)	1,065,987,174	151,497,745
54	56	86.825%	1,023,254,286	185,205,302	(94,853,501)	1,118,107,787	203,618,359
55	53	88.848%	1,025,079,986	187,031,001	(57,100,655)	1,082,180,641	167,691,212
56	57	90.886%	1,032,864,222	194,815,238	(94,853,501)	1,127,717,724	213,228,295
57	54	92.925%	1,032,932,265	194,883,280	(57,100,655)	1,090,032,920	175,543,491
58	58	95.254%	1,180,119,192	342,070,208	(82,124,847)	1,262,244,039	347,754,610
59	59	97.617%	1,197,207,939	359,158,954	(82,124,847)	1,279,332,785	364,843,357
60	60	100.000%	1,207,224,355	369,175,370	(82,124,847)	1,289,349,201	374,859,773
		mean =	**$ 844,432,610**	**$ 6,383,626**		**$ 920,875,469**	**$ 6,386,040**
		median =	833,224,091	(4,824,894)		901,154,939	(13,334,490)
		max =	1,207,224,355	369,175,370		1,289,349,201	374,859,773
		min =	584,664,131	(253,384,853)		633,562,293	(280,927,135)
		SD =	140,117,205	140,117,205		144,836,083	144,836,083
		SE =	18,089,053	18,089,053		18,698,258	18,698,258
		skew =	0.5291	0.5291		0.4350	0.4350
		kurt =	0.2984	0.2984		0.2574	0.2574
		N =	60	60		60	60
		df =	1	1		1	1
		Bera-Jarque =	2.9720	2.9720		2.0237	2.0237
		prob =	22.63%	22.63%		36.35%	36.35%