Enbridge #5

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please provide the results from all statistical hypothesis tests used to accept the specification of the truncated or restricted translog model rather than the full translog model presented in PEG's study.

RESPONSE

Our choice for the truncated or restricted translog models rested on the finding of negative elasticities for outputs of several of the firms in the dataset. Since it is unreasonable to rely on these, we had to restrict the model to generate reasonable output elasticities. We did not conduct any specification tests to accept the truncated models.

Witness: Mark Lowry

Enbridge #6

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please provide the following:

a. Indicate whether or not the estimated cost function in the June 20th study is concave in factor prices at each time period and for each of the 36 U.S. utilities.

b. Provide the statistical tests conducted to determine concavity.

c. If the function is not concave throughout the sample then provide the years and companies for which concavity is satisfied.

d. Using Enbridge and Union data, along with the estimates of the econometric cost model indicate whether or not the cost function is concave for all time periods, and if not then identify which years concavity is satisfied.

RESPONSE

a. The estimated cost functions in the June 20th studies (based on geometric decay and cost of service capital cost measurements) are concave in factor prices at each time period and for each of the 36 U.S. utilities.

b. The tests conducted to determine concavity can be found under validation of regularity conditions, in each of the final outputs/models provided in working paper folder (3.2.2). These tests indicate that the number of observations for which the matrix of second order partial derivatives of the cost function with respect to input prices is negative semi-definite is 100%, the number of observations for which the cost function is strictly quasi-concave in input prices is 100% and the number of observations for which the bordered Hessian is negative definite is 100%.

Witness: Mark Lowry

c. N/A

d. No comparable input prices were available for Enbridge and Union. Thus their data were not included in the sample used to estimate the model and there are no tests of concavity that include them. Please note that due to the price-quantity interaction terms in the cost models, it was necessary to assign input prices to Enbridge and Union in order to calculate company-specific elasticities.

We assigned the prices of Peoples Gas Light & Coke to Enbridge and the prices of East Ohio Gas to Union. The output elasticity estimates are little affected by output-price interaction terms. Thus, these assignments do not have a material effect on Union's and Enbridge's output elasticities.

Enbridge #7

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please provide all factor price elasticities, output elasticities, and rates of technological change for each U.S. utility and for each year in the sample period based on PEG's estimation results.

RESPONSE

All factor price and output elasticities, and rates of technological change are provided in EGD-7 elasticities CS.xls for the cost of service treatment of capital cost and in EGD-7 elasticities GD.xls for the geometric decay treatment of capital cost. These files are attached. Each file has two worksheets where the first is for the output and price elasticities, and the second is for rates of technological change by company and by year. The key for the heading of the first worksheets of both files is as follows:

* Firm-ID = the id that identifies each firm in the sample
* year = year of observation
* yn = is the elasticity for the number of customers
* yvrc = is the elasticity for residential & commercial deliveries
* yvoth = is the elasticity for other deliveries
* sumY = is the sum of the above three output elasticities
* WL = is the price elasticity for labor
* WK = is the price elasticity for capital

Witness: Mark Lowry

Enbridge #8

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please provide the residuals for each equation for PEG's econometric cost model.

RESPONSE

The file GD model residuals.xls, which is attached, provides the equation-by-equation residuals from the geometric decay capital cost model. The file CS model residuals.xls, which is also attached, provides the equation-by-equation residuals from the cost of service capital cost model.

Witness: Mark Lowry

Enbridge #9

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please provide the following:

a. Were adjustments made to the stochastic errors in PEG's econometric model for autocorrelation and/or heteroskedasticity?

b. If yes, please provide the complete details of how these adjustments were performed, including programming code, and spreadsheets.

c. Also please provide estimates of the model without these adjustments, including programming code, and spreadsheets.

RESPONSE

a. Adjustments were made to the stochastic errors in PEG's econometric models for heteroscedasticity.

b. Our correction for heteroscedasticity adjusts for unequal variances across groups or, in the present case, across firms. In general, the regression residuals (e_{it}) from the cost function can be written as $e_{it} = C_{it} - X_{it}\hat{\beta}$. Here C_{it} and X_{it} are the cost and explanatory variables, respectively, for the i^{th} firm at time period t, and $\hat{\beta}$ is a parameter estimate. Ordinarily, the variances of the regression residuals are used to compute standard errors assuming that their variance is constant across groups. These variances are likely to be unequal for many reasons, including greatly differing scales of operations in the groups of firms that make up the data, leading to erroneous statistical inference. As a result, we correct for such groupwise heteroscedasticity in our work.

Witness: Mark Lowry

To adjust for the presence of groupwise heteroscedasticity, we obtain initial parameter estimates and then we estimate residual variances for each group separately, with $e_i'e_i / n_i$ where e_i is the residual vector of group i : i.e. $e_i = C_i - X_i\hat{\beta}$. The residual variances are then used as weights to transform the original matrices of the dataset. In particular, the regressor and dependent variable matrices, X and Y, are pre-multiplied with these weights prior to estimation. Final estimates are obtained using the data transformed in this manner.

For the programming code that produced these please see the gauss code named SURH3UP.src found in working paper folder (3.2.2).

c. The models are provided in modelCS.txt and modelGD.txt, which are attached, for the cost of service and geometric decay treatments to capital cost, respectively. The main programming code DR_TC and the associated codes provided in working paper folder (3.2.2) are used to generate these models. The one additional code that is used is SUR.src, which is attached. Please note that in both models EGDI is found to have the opportunity to earn substantial incremental scale economies.

```
» run C:\Work\oebgas\Specification\DR_TC;

********************************************************************************

 Date:  8/31/07 ****    STANDARD SUR ESTIMATION RESULTS   ****   Time: 16:10:07

                        OUTPUT FILE:C:\work\Oebgas\results\out

                            DATA FILE:C:\work\Oebgas\oebgasCS.xls

********************************************************************************


                                DEFINITIONS OF OUTPUT VARIABLES:

                                Y1 is number of customers.

                                Y2 is weather adjusted residential & commerical deliveries

                                Y3 is other delivieries


                                DEFINITIONS OF BUSINESS CONDITION VARIABLES:

                                Z1 is % of non-iron miles in Dx miles

                                Z2 is Number of Electric Customers

                                Z3 is Urban Core Dummy

                                Model includes time trend.


                    Time period used: 1994 through 2004


***************************************************************************
                          GAUSS Data Import Facility
***************************************************************************

Begin import...
Import completed
Number of rows in input file:                  413
Number of cases written to GAUSS data set:     412
Number of missing elements:                    63
Number of variables written to GAUSS data set:  21
  1
409
===============================================================================
 LINEAR SEEMINGLY UNRELATED REGRESSION                     8/31/2007   4:10 pm
===============================================================================
                     Data Set:  C:\work\Oebgas\Temp_3.dat
-------------------------------------------------------------------------------


DIVISOR USING N IN EFFECT
RESTRICTIONS IN EFFECT

        ITER. # =    0    LOG OF DETERMINANT OF SIGMA =   -14.83848859
        ITER. # =    1    LOG OF DETERMINANT OF SIGMA =   -14.87836321
        ITER. # =    2    LOG OF DETERMINANT OF SIGMA =   -14.87866155
        ITER. # =    3    LOG OF DETERMINANT OF SIGMA =   -14.87866942
        ITER. # =    4    LOG OF DETERMINANT OF SIGMA =   -14.87866970
        ITER. # =    5    LOG OF DETERMINANT OF SIGMA =   -14.87866971
        ITER. # =    6    LOG OF DETERMINANT OF SIGMA =   -14.87866971

                   -----------------------------------
                             Equation:   1
                      Dependent variable:         C
                   -----------------------------------

     Total cases:              396    Valid cases:                    396
     Total SS:             316.532    Degrees of freedom:            ----
     R-squared:              0.969    Rbar-squared:                 0.969
     Residual SS:            9.656    Std error of est:             0.156
```

Durbin-Watson: 0.305

Variable	Estimated Coefficient	Standard Error	t-ratio	Prob >|t|
CONST	8.09998430	0.02740998	295.512	0.0000
WL	0.27399062	0.02125697	12.889	0.0000
WK	0.53854328	0.00719297	74.871	0.0000
Y1	0.69705852	0.04401660	15.836	0.0000
Y2	0.10424514	0.03408825	3.058	0.0024
Y3	0.06238929	0.02221964	2.808	0.0052
WLWL	0.06762728	0.19295385	0.350	0.7262
WLWK	-0.08265039	0.01659182	-4.981	0.0000
WKWK	0.16184785	0.01686196	9.598	0.0000
Y1Y1	0.17087483	0.03738302	4.571	0.0000
Y2Y2	-0.29552516	0.04118393	-7.176	0.0000
Y3Y3	0.01357016	0.01401523	0.968	0.3335
WLY1	-0.02035733	0.01546179	-1.317	0.1887
WLY2	0.00079847	0.01419459	0.056	0.9552
WLY3	0.00842856	0.00511423	1.648	0.1002
WKY1	-0.04255115	0.01588139	-2.679	0.0077
WKY2	0.03406274	0.01459514	2.334	0.0201
WKY3	0.01173716	0.00528727	2.220	0.0270
Z1	-0.60908554	0.05436684	-11.203	0.0000
Z2	-0.00833280	0.00111359	-7.483	0.0000
Z3	0.04242301	0.01693988	2.504	0.0127
TREND	-0.01119824	0.00262349	-4.268	0.0000
WLTREND	-0.00818099	0.00413322	-1.979	0.0485
WKTREND	0.00564213	0.00121339	4.650	0.0000

Equation: 2
Dependent variable: SL

Total cases:	396	Valid cases:	396
Total SS:	2.247	Degrees of freedom:	----
R-squared:	0.190	Rbar-squared:	0.206
Residual SS:	1.821	Std error of est:	0.068
Durbin-Watson:	0.407		

Variable	Estimated Coefficient	Standard Error	t-ratio	Prob >|t|
CONST	0.27399062	0.02125697	12.889	0.0000
WL	0.06762728	0.19295385	0.350	0.7262
WK	-0.08265039	0.01659182	-4.981	0.0000
Y1	-0.02035733	0.01546179	-1.317	0.1887
Y2	0.00079847	0.01419459	0.056	0.9552
Y3	0.00842856	0.00511423	1.648	0.1001
TREND	-0.00818099	0.00413322	-1.979	0.0485

Equation: 3
Dependent variable: SK

Total cases:	396	Valid cases:	396
Total SS:	2.617	Degrees of freedom:	----
R-squared:	0.243	Rbar-squared:	0.258
Residual SS:	1.983	Std error of est:	0.071
Durbin-Watson:	0.323		

Variable	Estimated Coefficient	Standard Error	t-ratio	Prob >|t|
CONST	0.53854328	0.00719297	74.871	0.0000
WL	-0.08265039	0.01659182	-4.981	0.0000
WK	0.16184785	0.01686196	9.598	0.0000
Y1	-0.04255115	0.01588139	-2.679	0.0077
Y2	0.03406274	0.01459514	2.334	0.0201
Y3	0.01173716	0.00528727	2.220	0.0270
TREND	0.00564213	0.00121339	4.650	0.0000

Equation: 4
Dependent variable: SM

Valid cases: 396

Degrees of freedom: ----

Variable	Estimated Coefficient	Standard Error	t-ratio	Prob >|t|
CONST	0.18746611	0.02110322	8.883	0.0000
WL	0.01502311	0.19167870	0.078	0.9376
WK	-0.07919745	0.01524060	-5.196	0.0000
Y1	0.06290847	0.01478495	4.255	0.0000
Y2	-0.03486121	0.01356161	-2.571	0.0109
Y3	-0.02016572	0.00488722	-4.126	0.0001

MEASURES OF GOODNESS-OF-FIT

AN UNCENTERED SYSTEM R-SQUARE 0.982

A CENTERED SYSTEM R-SQUARE 0.982

The results from the test of the null hypothesis that all slope coefficients in all equations are simultaneously equal to zero.

Test statistic	Prob > t
1588.097	+DEN

VALIDATION OF REGULARITY CONDITIONS

Monotonicity of the Estimated Cost Function

The number of observations for which each of the following predicted cost share is nonpositive is listed below

Labor	Capital	Materials
0 (0.00 %)	0 (0.00 %)	0 (0.00 %)

Concavity of the Estimated Cost Function

The number of the observations for which the condition that the matrix of second order partial derivatives of the cost function with respect to input wages is negative semi-definite holds:
396 (100.00 %)

Quasi-Concavity of the Estimated Cost Function

The number of observations for which the condition that the cost function is strictly quasi-concave in input prices holds:
396 (100.00 %)

Second Order Condition for Cost Minimization

The number of the observations for which the condition that the bordered Hessian is negative definite holds:
396 (100.00 %)

OUT-OF-SAMPLE PREDICTION OF TOTAL COST LEVEL PERFORMANCE LAST 3 YEARS

Actual	Predicted	Difference	t_ratio	p_value	Utility
8.245	8.636	-0.392	-4.291	0.000	East Ohio Gas
6.618	6.928	-0.310	-3.339	0.000	North Shore Gas
9.646	9.953	-0.307	-2.866	0.002	SOUTHERN CALIFORNIA GAS
6.189	6.430	-0.241	-2.508	0.006	Madison Gas & Electric
8.719	8.935	-0.216	-2.191	0.014	NICOR
7.669	7.877	-0.208	-2.248	0.012	SAN DIEGO GAS & ELECTRIC
6.803	6.989	-0.186	-2.126	0.017	Louisville Gas and Electric
7.503	7.635	-0.132	-1.428	0.077	Wisconsin Gas
8.576	8.707	-0.131	-1.378	0.084	Consolidated Edison
7.213	7.339	-0.125	-1.348	0.089	Illinois Power
6.468	6.556	-0.089	-0.923	0.178	Pg Energy (Penn Gas & Water)
7.752	7.833	-0.081	-0.870	0.192	Questar (Mountain Fuel Supply)
7.770	7.839	-0.069	-0.737	0.231	BALTIMORE GAS & ELECTRIC CO
8.424	8.474	-0.050	-0.525	0.300	Atlanta Gas Light
8.597	8.639	-0.042	-0.423	0.336	Peoples Gas Light
7.086	7.127	-0.040	-0.431	0.333	Rochester Gas and Electric
7.258	7.284	-0.026	-0.281	0.389	People's Natural Gas
7.163	7.164	-0.001	-0.015	0.494	COMMONWEALTH GAS
6.563	6.523	0.040	0.420	0.337	Wisconsin Power & Light
7.042	6.999	0.043	0.445	0.328	Connecticut Energy
7.834	7.791	0.044	0.467	0.320	Northwest Natural Gas
6.468	6.424	0.044	0.457	0.324	Orange & Rockland Utilities
7.673	7.619	0.054	0.560	0.288	new Jersey Natural Gas
8.510	8.438	0.072	0.769	0.221	Southwest Gas
7.010	6.914	0.096	0.944	0.173	Connecticut Natural Gas
8.844	8.747	0.097	1.023	0.153	Public Service Electric & Gas
7.716	7.615	0.102	1.087	0.139	Alabama Gas
8.556	8.438	0.118	1.240	0.108	Consumers Power
6.976	6.857	0.119	1.173	0.120	Cascade Natural Gas
7.955	7.782	0.172	1.854	0.032	Washington Natural Gas
6.039	5.789	0.250	2.468	0.007	Central Hudson Gas
7.373	7.091	0.283	3.128	0.001	Public Service of North Carolina
8.057	7.710	0.347	3.802	0.000	Niagra Mohawk
9.478	9.129	0.349	3.751	0.000	Pacific Gas & Electric
7.714	7.322	0.391	4.254	0.000	Peco (Philadelphia Electric)
8.465	7.959	0.506	5.766	0.000	Washington Gas Light

RTS (sum of output elasticities) calculated at all data points

sum	yn	yvrc	yvoth	utility
0.641	0.801	-0.230	0.070	ENBRIDGE
0.668	0.845	-0.251	0.074	NICOR
0.683	0.693	-0.064	0.054	Peoples Gas Light
0.714	0.819	-0.173	0.068	Consumers Power
0.717	0.809	-0.162	0.070	Public Service Electric & Gas
0.735	0.753	-0.085	0.067	East Ohio Gas
0.743	0.709	0.000	0.034	Washington Gas Light
0.758	0.722	-0.027	0.063	Consolidated Edison
0.782	0.749	-0.068	0.101	UNION GAS
0.791	0.626	0.101	0.064	Niagra Mohawk
0.795	0.965	-0.258	0.087	Pacific Gas & Electric
0.819	1.006	-0.278	0.091	SOUTHERN CALIFORNIA GAS
0.857	0.811	-0.016	0.063	Atlanta Gas Light
0.858	0.684	0.123	0.050	Questar (Mountain Fuel Supply)
0.867	0.630	0.190	0.047	Washington Natural Gas
0.867	0.398	0.441	0.027	Connecticut Natural Gas
0.884	0.559	0.287	0.038	People's Natural Gas
0.892	0.591	0.254	0.047	Peco (Philadelphia Electric)
0.896	0.394	0.472	0.031	North Shore Gas
0.897	0.631	0.209	0.056	Wisconsin Gas
0.904	0.491	0.377	0.036	COMMONWEALTH GAS

0.906	0.567	0.303	0.037	new Jersey Natural Gas
0.908	0.648	0.210	0.050	BALTIMORE GAS & ELECTRIC CO
0.912	0.517	0.360	0.035	Rochester Gas and Electric
0.940	0.422	0.477	0.041	Pg Energy (Penn Gas & Water)
0.941	0.581	0.311	0.049	Illinois Power
0.944	0.359	0.546	0.038	Orange & Rockland Utilities
0.947	0.784	0.100	0.063	Southwest Gas
0.956	0.611	0.286	0.059	Northwest Natural Gas
0.965	0.536	0.391	0.038	Louisville Gas and Electric
0.971	0.371	0.582	0.018	Madison Gas & Electric
0.985	0.421	0.530	0.035	Connecticut Energy
1.002	0.600	0.344	0.058	Alabama Gas
1.016	0.558	0.412	0.046	Public Service of North Carolina
1.029	0.420	0.569	0.039	Wisconsin Power & Light
1.061	0.434	0.561	0.066	Cascade Natural Gas
1.064	0.253	0.779	0.032	Central Hudson Gas
1.065	0.684	0.320	0.061	SAN DIEGO GAS & ELECTRIC

»

```
» run C:\Work\oebgas\Specification\DR_TC;

********************************************************************************

 Date:  8/31/07 ****    STANDARD SUR ESTIMATION RESULTS   ****   Time: 16:07:01

                        OUTPUT FILE:C:\work\Oebgas\results\out

                            DATA FILE:C:\work\Oebgas\oebgas5.xls

********************************************************************************

                                DEFINITIONS OF OUTPUT VARIABLES:

                                Y1 is number of customers.

                                Y2 is weather adjusted residential & commerical deliveries

                                Y3 is other delivieries

                                DEFINITIONS OF BUSINESS CONDITION VARIABLES:

                                Z1 is % of non-iron miles in Dx miles

                                Z2 is Number of Electric Customers

                                Z3 is Urban Core Dummy

                                Model includes time trend.

                    Time period used: 1994 through 2004


***************************************************************************
                          GAUSS Data Import Facility
***************************************************************************

Begin import...
Import completed
Number of rows in input file:                413
Number of cases written to GAUSS data set:     412
Number of missing elements:                    63
Number of variables written to GAUSS data set:  21
  1
409
===============================================================================
 LINEAR SEEMINGLY UNRELATED REGRESSION                       8/31/2007   4:07 pm
===============================================================================
                     Data Set:  C:\work\Oebgas\Temp_3.dat
-------------------------------------------------------------------------------


DIVISOR USING N IN EFFECT
RESTRICTIONS IN EFFECT

        ITER. # =    0    LOG OF DETERMINANT OF SIGMA =   -15.07726690
        ITER. # =    1    LOG OF DETERMINANT OF SIGMA =   -15.11387101
        ITER. # =    2    LOG OF DETERMINANT OF SIGMA =   -15.11417859
        ITER. # =    3    LOG OF DETERMINANT OF SIGMA =   -15.11418634
        ITER. # =    4    LOG OF DETERMINANT OF SIGMA =   -15.11418659
        ITER. # =    5    LOG OF DETERMINANT OF SIGMA =   -15.11418660
        ITER. # =    6    LOG OF DETERMINANT OF SIGMA =   -15.11418660

                   -----------------------------------
                              Equation:   1
                     Dependent variable:         C
                   -----------------------------------

     Total cases:              396    Valid cases:                    396
     Total SS:             316.905    Degrees of freedom:            ----
     R-squared:              0.971    Rbar-squared:                 0.970
     Residual SS:            9.195    Std error of est:             0.152
```

Durbin-Watson: 0.303

Variable	Estimated Coefficient	Standard Error	t-ratio	Prob >|t|
CONST	8.15930715	0.02669576	305.641	0.0000
WL	0.25117202	0.02008446	12.506	0.0000
WK	0.57185028	0.00712666	80.241	0.0000
Y1	0.64647326	0.04289936	15.070	0.0000
Y2	0.15652898	0.03324091	4.709	0.0000
Y3	0.06776143	0.02165798	3.129	0.0019
WLWL	0.03019952	0.18110708	0.167	0.8677
WLWK	-0.06506122	0.01686791	-3.857	0.0001
WKWK	0.15431853	0.01747587	8.830	0.0000
Y1Y1	0.15614263	0.03641646	4.288	0.0000
Y2Y2	-0.27659896	0.04011523	-6.895	0.0000
Y3Y3	0.01527058	0.01365529	1.118	0.2641
WLY1	-0.00564046	0.01478471	-0.382	0.7030
WLY2	-0.01309131	0.01358868	-0.963	0.3360
WLY3	0.00683601	0.00487198	1.403	0.1614
WKY1	-0.05916258	0.01551001	-3.814	0.0002
WKY2	0.05196239	0.01426865	3.642	0.0003
WKY3	0.01267151	0.00514416	2.463	0.0142
Z1	-0.58541029	0.05294690	-11.057	0.0000
Z2	-0.00826632	0.00108491	-7.619	0.0000
Z3	0.04221989	0.01649696	2.559	0.0109
TREND	-0.00911713	0.00256454	-3.555	0.0004
WLTREND	-0.00671587	0.00390919	-1.718	0.0866
WKTREND	0.00473124	0.00123348	3.836	0.0001

Equation: 2
Dependent variable: SL

Total cases:	396	Valid cases:	396
Total SS:	1.940	Degrees of freedom:	----
R-squared:	0.148	Rbar-squared:	0.165
Residual SS:	1.653	Std error of est:	0.065
Durbin-Watson:	0.405		

Variable	Estimated Coefficient	Standard Error	t-ratio	Prob >|t|
CONST	0.25117202	0.02008446	12.506	0.0000
WL	0.03019952	0.18110708	0.167	0.8677
WK	-0.06506122	0.01686791	-3.857	0.0001
Y1	-0.00564046	0.01478471	-0.382	0.7030
Y2	-0.01309131	0.01358868	-0.963	0.3359
Y3	0.00683601	0.00487198	1.403	0.1613
TREND	-0.00671587	0.00390919	-1.718	0.0866

Equation: 3
Dependent variable: SK

Total cases:	396	Valid cases:	396
Total SS:	2.429	Degrees of freedom:	----
R-squared:	0.228	Rbar-squared:	0.243
Residual SS:	1.876	Std error of est:	0.069
Durbin-Watson:	0.327		

Variable	Estimated Coefficient	Standard Error	t-ratio	Prob >|t|
CONST	0.57185028	0.00712666	80.241	0.0000
WL	-0.06506122	0.01686791	-3.857	0.0001
WK	0.15431853	0.01747587	8.830	0.0000
Y1	-0.05916258	0.01551001	-3.814	0.0002
Y2	0.05196239	0.01426865	3.642	0.0003
Y3	0.01267151	0.00514416	2.463	0.0142
TREND	0.00473124	0.00123348	3.836	0.0001

Equation: 4
Dependent variable: SM

Valid cases: 396
Degrees of freedom: ----

Variable	Estimated Coefficient	Standard Error	t-ratio	Prob >|t|
CONST	0.17697770	0.01986353	8.910	0.0000
WL	0.03486170	0.17992471	0.194	0.8466
WK	-0.08925731	0.01533513	-5.820	0.0000
Y1	0.06480305	0.01401352	4.624	0.0000
Y2	-0.03887108	0.01286792	-3.021	0.0029
Y3	-0.01950751	0.00461424	-4.228	0.0000

MEASURES OF GOODNESS-OF-FIT

AN UNCENTERED SYSTEM R-SQUARE 0.983

A CENTERED SYSTEM R-SQUARE 0.983

The results from the test of the null hypothesis that all slope coefficients in all equations are simultaneously equal to zero.

Test statistic	Prob > t
1603.947	0.0000

VALIDATION OF REGULARITY CONDITIONS

Monotonicity of the Estimated Cost Function

The number of observations for which each of the following predicted cost share is nonpositive is listed below

Labor	Capital	Materials
0 (0.00 %)	0 (0.00 %)	0 (0.00 %)

Concavity of the Estimated Cost Function

The number of the observations for which the condition that the matrix of second order partial derivatives of the cost function with respect to input wages is negative semi-definite holds:
396 (100.00 %)

Quasi-Concavity of the Estimated Cost Function

The number of observations for which the condition that the cost function is strictly quasi-concave in input prices holds:
396 (100.00 %)

Second Order Condition for Cost Minimization

The number of the observations for which the condition that the bordered Hessian is negative definite holds:
396 (100.00 %)

OUT-OF-SAMPLE PREDICTION OF TOTAL COST LEVEL PERFORMANCE LAST 3 YEARS

Actual	Predicted	Difference	t_ratio	p_value	Utility
8.307	8.684	-0.378	-4.250	0.000	East Ohio Gas
6.674	6.983	-0.310	-3.431	0.000	North Shore Gas
9.711	9.999	-0.287	-2.748	0.003	SOUTHERN CALIFORNIA GAS
6.233	6.485	-0.252	-2.682	0.004	Madison Gas & Electric
6.802	7.015	-0.213	-2.512	0.006	Louisville Gas and Electric
7.719	7.921	-0.203	-2.238	0.013	SAN DIEGO GAS & ELECTRIC
8.819	8.999	-0.181	-1.875	0.031	NICOR
7.533	7.684	-0.151	-1.681	0.047	Wisconsin Gas
8.632	8.777	-0.146	-1.576	0.058	Consolidated Edison
7.322	7.384	-0.062	-0.684	0.247	Illinois Power
8.443	8.504	-0.061	-0.663	0.254	Atlanta Gas Light
7.828	7.882	-0.055	-0.600	0.274	Questar (Mountain Fuel Supply)
6.578	6.632	-0.054	-0.579	0.281	Pg Energy (Penn Gas & Water)
7.831	7.878	-0.047	-0.519	0.302	BALTIMORE GAS & ELECTRIC CO
7.200	7.232	-0.032	-0.350	0.363	COMMONWEALTH GAS
8.674	8.692	-0.018	-0.183	0.427	Peoples Gas Light
7.179	7.185	-0.006	-0.067	0.473	Rochester Gas and Electric
7.353	7.346	0.006	0.071	0.472	People's Natural Gas
7.705	7.683	0.022	0.236	0.407	new Jersey Natural Gas
6.599	6.569	0.030	0.325	0.373	Wisconsin Power & Light
6.527	6.495	0.032	0.342	0.366	Orange & Rockland Utilities
7.096	7.052	0.044	0.461	0.322	Connecticut Energy
7.888	7.842	0.045	0.500	0.309	Northwest Natural Gas
8.521	8.456	0.065	0.702	0.241	Southwest Gas
8.895	8.828	0.067	0.725	0.234	Public Service Electric & Gas
7.711	7.636	0.074	0.813	0.208	Alabama Gas
7.072	6.972	0.100	1.005	0.157	Connecticut Natural Gas
7.028	6.919	0.109	1.104	0.135	Cascade Natural Gas
8.618	8.506	0.112	1.207	0.114	Consumers Power
7.978	7.842	0.136	1.498	0.067	Washington Natural Gas
6.084	5.857	0.227	2.301	0.011	Central Hudson Gas
7.372	7.110	0.262	2.960	0.002	Public Service of North Carolina
9.551	9.221	0.330	3.639	0.000	Pacific Gas & Electric
8.123	7.781	0.343	3.840	0.000	Niagra Mohawk
7.791	7.371	0.420	4.726	0.000	Peco (Philadelphia Electric)
8.511	8.023	0.489	5.688	0.000	Washington Gas Light

RTS (sum of output elasticities) calculated at all data points

sum	yn	yvrc	yvoth	utility
0.660	0.742	-0.156	0.075	ENBRIDGE
0.687	0.781	-0.176	0.081	NICOR
0.700	0.639	0.002	0.058	Peoples Gas Light
0.729	0.761	-0.107	0.075	Consumers Power
0.733	0.747	-0.091	0.077	Public Service Electric & Gas
0.750	0.695	-0.018	0.072	East Ohio Gas
0.752	0.659	0.057	0.036	Washington Gas Light
0.771	0.661	0.042	0.068	Consolidated Edison
0.800	0.693	-0.004	0.110	UNION GAS
0.804	0.581	0.154	0.069	Niagra Mohawk
0.805	0.891	-0.182	0.096	Pacific Gas & Electric
0.827	0.926	-0.199	0.100	SOUTHERN CALIFORNIA GAS
0.863	0.757	0.038	0.068	Atlanta Gas Light
0.864	0.639	0.169	0.055	Questar (Mountain Fuel Supply)
0.872	0.584	0.237	0.051	Washington Natural Gas
0.874	0.371	0.474	0.028	Connecticut Natural Gas
0.888	0.522	0.326	0.040	People's Natural Gas
0.897	0.551	0.295	0.051	Peco (Philadelphia Electric)
0.902	0.367	0.503	0.032	North Shore Gas
0.902	0.589	0.252	0.061	Wisconsin Gas
0.908	0.457	0.412	0.038	COMMONWEALTH GAS

0.909	0.523	0.346	0.039	new Jersey Natural Gas
0.911	0.605	0.253	0.054	BALTIMORE GAS & ELECTRIC CO
0.915	0.480	0.397	0.037	Rochester Gas and Electric
0.943	0.541	0.349	0.053	Illinois Power
0.945	0.399	0.502	0.044	Pg Energy (Penn Gas & Water)
0.948	0.733	0.146	0.069	Southwest Gas
0.949	0.335	0.573	0.040	Orange & Rockland Utilities
0.958	0.568	0.327	0.064	Northwest Natural Gas
0.964	0.504	0.420	0.040	Louisville Gas and Electric
0.971	0.351	0.601	0.018	Madison Gas & Electric
0.986	0.394	0.555	0.037	Connecticut Energy
1.002	0.559	0.380	0.062	Alabama Gas
1.013	0.527	0.438	0.049	Public Service of North Carolina
1.027	0.397	0.588	0.041	Wisconsin Power & Light
1.059	0.634	0.359	0.067	SAN DIEGO GAS & ELECTRIC
1.062	0.404	0.586	0.071	Cascade Natural Gas
1.062	0.237	0.792	0.034	Central Hudson Gas

»

```
/*-----------------------------------------------------------------------------

      Procedure:        SUR.src
      Written by:       Donald J Wyhowski
      Written:          May 1, 2000
      Last changed:     June 7, 2000

      Note........:     This program estimates a system of equations using the
                              iterated Seemingly Unrelated Regression (SUR)
technique.

-----------------------------------------------------------------------------*/


/*
      Format:   Q = SUR(dataset,LHS_vars,RHS_vars,NUM_var,Restrict)

      Input:    dataset  -- string, name of GAUSS data set.

                LHS_vars -- character vector of all dependent variable
                          names in the systems.  Example:

                            LHS_vars = { y1,y2,y3 };

             RHS_vars -- character vector of all independent variable
                         names in the systems.  The order of the
                         variable names must correspond to the order
                         of the equations when they are stacked.  Put
                         "CONST" in the RHS_vars list if constant term
                         is needed.  Example:

                            RHS_vars = { const,x1,x2,x3,     @ 1st eqn. @
                                         const,x2,x3,x4,     @ 2nd eqn. @
                                         const,x1,x3,x5 };   @ 3rd eqn. @

             NUM_var  -- numeric vector to determine the number of right-
                         hand side variables in each equation.  Following
                         the above example:

                            NUM_var = { 4,4,4 };

             Restrict -- string, constrainted information on parameters
                         to perform restricted estimation.  The syntax
                         of Restrict is as follows:

                            Restrict="rest1, rest2,...., restN";

                         More than one restriction is allowed provided
                         each is separated by commas.  Each restriction
                         must be written as a linear equation with all
                         variables in the left-hand side and the constant
                         in the right-hand side (i.e., x1:1+x1:2=1).
                         Variables shown in each restriction must be
                         variables in the regression model.  Note that
                         the numeric value following the (:) signifies
```

which equation the variable comes from (i.e., X4:10 indicates the X4 variable comes from the 10th equation). Restrictions in the RESTRICT argument must be consistent and not redundant otherwise error messages will be given. Users should note that only the parameters associated with the variables are restricted, and not the variables in the model.

Examples of some restrict arguments:

```
1)  Restrict="x1:1 + x1:2 + x1:3 = 1";
2)  Restrict="const:1 + const:2 + const:3 = 1,
              trend:1 = 0,
              trend:2 = 0,
              trend:3 = 0";
```

Output:

Q -- a "COMPACT" output vector containing all calculated statistics. See manual for more details on extracting information from it. Variables contained in Q are:

```
nms   -- name of the regressors.
b     -- regression coefficients.
vc    -- variance-covariance matrix of b.
se    -- standard error of b.
s2    -- variance of the error.
cx    -- correlation matrix of b.
rsq   -- coefficient of determination.
rbsq  -- adjusted R-squared.
dw    -- Durbin-Watson statistic.
nobs  -- number of observations.
sigma -- residual covariance matrix.
sse   -- residual sum of square.
```

Globals:

_lrdv -- scalar. Determines which divisor is used to compute the covariance matrix of the error.

0 T-(K/M) is used as divisor, where T is the number of observations, K is the number of all right-hand side variables in the systems, and M is the total number of equations. Hence, (K/M) is the average number of coefficients per equation.

1 T is used as divisor. Users are encouraged to use this, since it provides good asmptotic properties for the estimator.

Default = 1.

_lriter -- scalar. Sets the maximum number of iterations for the iterated seemingly unrelated regression. The iterative process is also subject to the convergence criterion _lrtol. Default = 1.

```
              __output -- scalar.  If nonzero, results are printed.
                          Default = 2.

            _lrpcor    -- scalar.  If 1, print the correlation matrix of
                          all coefficients in the systems after convergence.
                          Default = 0.

            _lrpcov    -- scalar.  If 1, print the covariance matrix of
                          all coefficients in the systems after convergence.
                          Default = 0.

              __range  -- a 2 x 1 vector.  Specifies the range of the
                          data set to be used in estimation.  The first
                          element specifies the beginning observation
                          while the second element specifies the ending
                          observation.

                          Example: __range = { 100,200 }.

                          Default is { 0,0 } and uses the whole data set.

             _lrtol    -- scalar.  Specifies a convergence criterion to
                          stop the iterative process.  The iterative
                          process will continue until either the iteration
                          limit specified in _lriter is reached or the
                          percentage change in the log of determinant of
                          sigma is less than the convergence criterion.
                          Default = 0.0001.

              __title  -- string, message printed at the top of the
                          results.  Default ="";

*/

#include lr.ext;
#include gauss.ext;

proc(1) = sur(dataset,LHS_vars,RHS_vars,NUM_var,restrict);

    local oldtrap,start,counter,count1,lastobs,err,iter,maxiter,pcd,
          lnsig_o,lnsig_n,R,rank_R,z,invRCR,tobs,nobs,fp,nr,i,j,g,mk,lb,ub,
          lbi,ubi,lbj,ubj,sst,rsq,rbsq,readisk,what,vnames,names,
          indx,xzx,xzy,sig,isig,b,c,s,cm,se,se0,t1,t_temp,t2,df,dta,
          ixxtemp,xx,xy,e,yy,y,sse,ybar,sumy,tsumy,dw,tdw,ef,e1,
          errmsg,Y_index,X_index,Q,rr;

    if __output;
       call header("LINEAR SEEMINGLY UNRELATED REGRESSION",
                   dataset,0);
    endif;

    dataset = "" $+ dataset;
    fp = -1;
    open fp = ^dataset;
    if fp == -1;
        goto errout("Data file: " $+ dataset,1);
```

```
    endif;
    if sumc(NUM_var) /= rows(RHS_vars);
        goto errout("# of RHS_vars = " $+ ftos(rows(RHS_vars),"%*.*lf",1,0)
                    $+ "     Total NUM_var = " $+
                    ftos(sumc(NUM_var),"%*.*lf",1,0),36);
    endif;

    { nr,start,counter,lastobs } = _rngchk(dataset,__range);

nr=lastobs;

    if __output;
       print;
       if (start /= 1 or lastobs /= rowsf(fp));
          print ("SAMPLE RANGE SET TO: "
                  $+ ftos(__range[1],"%*.*lf",1,0)
                  $+ " TO " $+ ftos(__range[2],"%*.*lf",1,0));
       endif;
       if _lrdv == 1;
          print "DIVISOR USING N IN EFFECT";
       endif;
       if type(restrict) == 13;
          print "RESTRICTIONS IN EFFECT ";
       endif;
    endif;

    tobs = lastobs-start+1;
    what = { const };
    { vnames, indx } = indices(dataset,0);
    clear indx;

    if not what $/= RHS_vars;
       vnames = "CONST"|vnames;
    endif;

    if ismiss(indcv((LHS_vars|RHS_vars),vnames));
        goto errout("Check the variable names carefully",2);
    endif;

    if type(restrict) == 13;
       restrict=chrs(packr(miss(miss(miss(vals(restrict),10),13),32)));
       { R,z }=SRMatrix(restrict,RHS_vars,NUM_var);
       if scalerr(R);
          goto errout("",scalerr(R));
       endif;
    endif;

    Y_index = indcv(LHS_vars,vnames);
    X_index = indcv(RHS_vars,vnames);

    nobs = 0;
    xx=0;
    xy=0;
    call seekr(fp,start);
    count1=counter;
    do while count1 < lastobs;
       dta=readr(fp,nr);
```

```
   count1=count1+rows(dta);
   if count1 > lastobs;
      dta = trimr(dta,0,count1-lastobs);
   endif;
   dta=packr(dta);
   if ismiss(dta);
      continue;
   endif;
   nobs = nobs + rows(dta);
   if not what $/= RHS_vars;
      dta = ones(rows(dta),1)~dta;
   endif;
   xx = xx + dta[.,X_index]'*dta[.,X_index];
   xy = xy + dta[.,X_index]'*dta[.,Y_index];
endo;

g=rows(NUM_var);
b=zeros(rows(RHS_vars),1);
lb=1;
ub=0;
i=1;
do while i <= g;
   ub = NUM_var[i] + ub;
   oldtrap = trapchk(65535);
   trap 1;
   ixxtemp=invpd(xx[lb:ub,lb:ub]);
   trap oldtrap;
   if scalerr(ixxtemp);
      goto errout("",30);
   endif;
   b[lb:ub]=ixxtemp*xy[lb:ub,i];
   lb = ub + 1;
   i = i + 1;
endo;

if type(restrict) == 13;
   c=zeros(rows(RHS_vars),rows(RHS_vars));
   lb=1;
   ub=0;
   i=1;
   do while i <= g;
      ub=NUM_var[i]+ub;
      c[lb:ub,lb:ub] = xx[lb:ub,lb:ub];
      lb=ub+1;
      i=i+1;
   endo;
   c=invpd(c);

   oldtrap = trapchk(65535);
   trap 1;
   invRCR = invpd(R*c*R');
   trap oldtrap;
   if scalerr(invRCR);
      goto errout("",30);
   endif;
   b = b - (c*R')*invRCR*(R*b-z);
endif;
```

```
{ sig }=LRsse(dataset,LHS_vars,RHS_vars,NUM_var,b);

if _lrdv == 1;
   sig = sig./nobs;
else;
   sig = sig./(nobs-(rows(RHS_vars)/rows(NUM_var)));
endif;

lnsig_o = ln(det(sig));
if __output;
   print;
   print ftos(0,"        ITER. # = %*.*lf",4,0);;
   print ftos(lnsig_o,"    LOG OF DETERMINANT "\
              "OF SIGMA = %*.*lf",14,8);
endif;

iter=1;
pcd=abs(lnsig_o);
maxiter = maxc(_lriter|1);
do while ((iter <= maxiter) and (pcd >= _lrtol));
   isig = invpd(sig);
   mk = sumc(NUM_var);
   xzx = zeros(mk,mk);
   xzy = zeros(mk,1);
   i = 1;
   lbi = 1;
   ubi = 0;
   do while i <= rows(NUM_var);
      ubi = NUM_var[i] + ubi;
      j = 1;
      lbj = 1;
      ubj = 0;
      do while j <= rows(NUM_var);
         ubj = NUM_var[j] + ubj;
         if i == j;
            xzx[lbi:ubi,lbj:ubj]=isig[i,j]*xx[lbi:ubi,lbj:ubj];
         elseif j > i;
            xzx[lbi:ubi,lbj:ubj]=isig[i,j]*xx[lbi:ubi,lbj:ubj];
         elseif j < i;
            xzx[lbi:ubi,lbj:ubj] = xzx[lbj:ubj,lbi:ubi]';
         endif;
         xzy[lbi:ubi] = xzy[lbi:ubi]+isig[i,j]*xy[lbi:ubi,j];
         j = j + 1;
         lbj = ubj + 1;
      endo;
      i = i + 1;
      lbi = ubi + 1;
   endo;

   oldtrap = trapchk(65535);
   trap 1;
   c = invpd(xzx);
   trap oldtrap;
   if scalerr(c);
      goto errout("",30);
   endif;
```

```
   b = c*xzy;

   if type(restrict) == 13;
      oldtrap = trapchk(65535);
      trap 1;
      invRCR = invpd(R*c*R');
      trap oldtrap;
      if scalerr(invRCR);
         goto errout("",30);
      endif;
      b = b - (c*R')*invRCR*(R*b-z);
      c = c - (c*R')*invRCR*(R*c);
   endif;

   se = sqrtabs(diag(c));
   se0 = se .==0;
   t_temp = b./(se+se0);
   t1 = t_temp + miss(se0,1);
   df = zeros(g,1);
   t2 = zeros(rows(t1),1);
   lb=1;
   ub=0;
   i=1;
   do while i <= g;
      ub=NUM_var[i]+ub;
      if type(restrict) == 13;
         df[i]=nobs-NUM_var[i]+rows(R);
      else;
         df[i]=nobs-NUM_var[i];
      endif;
      t2[lb:ub] = 2*cdftc(abs(t_temp[lb:ub]),df[i]);
      t2[lb:ub] = t2[lb:ub]+miss(se0[lb:ub],1);
      lb=ub+1;
      i=i+1;
   endo;

   { sig }=LRsse(dataset,LHS_vars,RHS_vars,NUM_var,b);

   if _lrdv == 1;
      sig = sig./nobs;
   else;
      sig = sig./(nobs-(rows(RHS_vars)/rows(NUM_var)));
   endif;


   lnsig_n = ln(det(sig));
   pcd = abs((lnsig_n - lnsig_o)/lnsig_o)*100;
   if __output;
      print ftos(iter,"        ITER. # = %*.*lf",4,0);;
      print ftos(lnsig_n,"    LOG OF DETERMINANT OF "\
                 "SIGMA = %*.*lf",14,8);
   endif;
   lnsig_o = lnsig_n;
   iter=iter+1;

endo;
```

```
yy=0;
sse=0;
sumy=0;
ybar=0;
dw=0;
ef = zeros(1,g);
readisk = 0;
call seekr(fp,start);
count1=counter;
do while count1 < lastobs;
   dta=readr(fp,nr);
   count1=count1+rows(dta);
   if count1 > lastobs;
      dta = trimr(dta,0,count1-lastobs);
   endif;
   dta=packr(dta);
   if ismiss(dta);
      continue;
   endif;
   if not what $/= RHS_vars;
      dta=ones(rows(dta),1)~dta;
   endif;
   y=zeros(rows(dta),g);
   e=zeros(rows(dta),g);
   e1=e;
   tsumy=zeros(g,1);
   tdw=zeros(g,1);
   i=1;
   lb=1;
   ub=0;
   do while i <= g;
      ub=NUM_var[i]+ub;
      y[.,i]=dta[.,indcv(LHS_vars[i],vnames)];
      e[.,i]=dta[.,indcv(LHS_vars[i],vnames)] -
               dta[.,indcv(RHS_vars[lb:ub],vnames)]*b[lb:ub];
      tsumy[i]=tsumy[i]+sumc(y[.,i]);
      e1[.,i] = lag(e[.,i]);
      e1[1,i] = ef[.,i];
      ef[.,i]=e[rows(y[.,i]),i];
      if readisk == 0;
           tdw[i]=tdw[i]+sumc((e[.,i] - e1[.,i])^2) - e[1,i]^2;
      else;
           tdw[i]=tdw[i]+sumc((e[.,i] - e1[.,i])^2);
      endif;
      i=i+1;
      lb=ub+1;
   endo;
   sse=sse+diag(moment(e,0));
   yy=yy+diag(moment(y,0));
   sumy=sumy+tsumy;
   dw=dw+tdw;
   readisk = readisk + 1;
endo;

ybar=sumy./nobs;
dw=dw./sse;
```

```
i=1;
lb=1;
ub=0;
sst=0;
rsq=zeros(g,1);
rbsq=0;
do until i > g;
   ub = NUM_var[i] + ub;
   names = LHS_vars[i]|RHS_vars[lb:ub];
   sst=yy[i] - nobs*(ybar[i]^2);
   rsq[i]=1-(sse[i]/sst);
   rbsq=1-((nobs-1)/df[i])*(1-rsq[i]);
   if __output;
      call LRprt(i,names,tobs,nobs,sst,df[i],rsq[i],rbsq,sse[i],
                 sig[i,i],"nofstat",0,0,dw[i],b[lb:ub],se[lb:ub],
                 t1[lb:ub],t2[lb:ub],_lrdv);
   endif;
   lb = ub + 1;
   i = i + 1;
endo;

s=1./sqrtabs(diag(c));
cm=(s.*c).*s';

if __output;
   if _lrpcov;
      print;
      matwrt("VARIANCE-COVARIANCE MATRIX OF ESTIMATES",
               c,RHS_vars,RHS_vars,4);
   endif;
   if _lrpcor;
      print;
      matwrt("CORRELATION MATRIX OF ESTIMATES",
               cm,RHS_vars,RHS_vars,4);
   endif;
endif;

Q = 0;     /* initialize the the output vector */
Q = vput(Q,"LSUR","model");
Q = vput(Q,RHS_vars,"nms");
Q = vput(Q,NUM_var,"novars");
Q = vput(Q,b,"b");
Q = vput(Q,c,"vc");
Q = vput(Q,se,"se");
Q = vput(Q,diag(sig),"s2");
Q = vput(Q,cm,"cx");
Q = vput(Q,rsq,"rsq");
Q = vput(Q,dw,"dw");
Q = vput(Q,sse,"sse");
Q = vput(Q,nobs,"nobs");
Q = vput(Q,sig,"sigma");

if fp > 0;
   fp=close(fp);
endif;

retp(Q);
```

```
errout:
    pop err;
    pop errmsg;

    if not trapchk(1);
       lrerror(errmsg,err);
       errorlog "LSUR estimation won't be done!";
       end;
    endif;
    if fp > 0;
       fp=close(fp);
    endif;
    retp(error(err));

endp;
```

Enbridge #10

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please re-estimate the cost model such that the output variables from the June 20, 2007 study are replaced by the weather normalizing equations provided at the top of page 72 that characterize output quantities. Provide the data, computer code and spreadsheets and complete estimation results.

RESPONSE

Please note that models and results using weather normalized residential & commercial deliveries were already provided in the report.

Witness: Mark Lowry

Enbridge #11

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

On page 46 of the June 20, 2007 report, PEG reports,

> "As an extra check, we regressed the growth in the TFP of our sampled U.S. utilities (using both approaches to capital costing) on the change in their cast iron reliance using data for the sample period. Using each approach, the estimated effect of reduced reliance on cost was negative (suggesting that it raises cost), but the hypothesis that a change in cast iron reliance has no effect on TFP growth could not be rejected at a high level of confidence. Our research does not then prompt us to adjust the econometric TFP target for Enbridge to reflect its plan for cast iron reduction."

Please provide all computer code, spreadsheets, data and other work papers that PEG relied upon for these statements / conclusions. Please provide all materials in usable electronic format.

RESPONSE

Please see the excel file TFP growth drivers.xls, which is attached, for the analysis that we relied on to indicate that change in cast iron reliance has no statistically significant effect on TFP growth. This file has six worksheets:

1) Indexes worksheet (includes the TFP indices, percent non-cast iron and electric customer numbers, and their respective growth rates by year)
    - tfpndx2GD is TFP computed using an output index constructed with elasticity estimates that rely on the geometric decay treatment of capital cost
    - tfpndx2cos is TFP computed using an output index constructed with elasticity estimates that rely on the cost of service treatment of capital cost

- pctnirn is percent non-cast iron
- yne is the number of electric customers

2) reg1CS worksheet is the regression of change in TFP, with the cost of service treatment, on change in the percent non-cast iron. It indicates that less reliance on cast iron lowers growth in TFP, but this effect is not statistically significant.
3) reg2CS worksheet is the same as reg1CS but includes the growth in the number of electric customers, the other business condition found to affect cost in the econometric work and that varies by time. (Please note the third business condition, the urban core dummy, is not part of this work since it is a time-invariant variable). Here again, neither less reliance on cast-iron nor the change in the number of electric customers is found to have a statistically significant effect on growth in TFP.
4) reg1GD worksheet is the counterpart to reg1CS, but uses the geometric decay treatment of capital in the construction of TFP, and this regression supports the same finding.
5) reg2GD worksheet is the geometric decay counterpart to reg2CS and also provides the same conclusion.
6) reg-data worksheet provides the actual regression data based on the growth rates of all the variables used to generate the regression outputs.

Enbridge #14

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

On page 82 of PEG's June 20, 2007 report, it is stated,

> "In attempting to operationalize the use of company specific elasticities in our calculations, we discovered that the translog cost function generated some unreasonable values for these. We experimented with several alternative specifications and finally settled on one which differed from the translog form only in excluding the 'output interaction' terms."

a. Please provide all computer code, spreadsheets, data and other work papers associated with the estimation of all translog cost function that generated unreasonable values for company specific elasticities.

b. Please provide tables of results associated with these estimations in the same format as Table 19a and Table 19b.

c. Please provide all company specific elasticities associated with these estimations.

d. Please identify all company specific elasticities provided in c. that were unreasonable, and an explanation of why PEG considered them to be unreasonable.

RESPONSE

a. Please see working paper folder 3.2.2, which was provided in response to question 2.

b. The tables of results associated with these estimations are provided in the attached file EGD-14 full translog cost function models.xls.

Witness: Mark Lowry

c. The company specific elasticities associated with these estimates can be found in the attached files EGD-14 output elasticities with full model GD.txt and EGD-14 output elasticities with full model CS.txt.

d. We consider all negative elasticities to be unreasonable since these imply a negative marginal cost. The finding that cost is non-decreasing in output is a basic result of econometric theory.

EGD-14 output elasticities with full model CS.txt

RTS (sum of output elasticities) calculated at all data points

sum	yn	yvrc	yvoth	utility
0.375	0.832	-0.592	0.135	ENBRIDGE
0.414	0.692	-0.111	-0.168	Washington Gas Light
0.415	0.669	-0.250	-0.004	Peoples Gas Light
0.474	0.893	-0.626	0.207	NICOR
0.554	0.840	-0.447	0.161	Public Service Electric & Gas
0.563	0.855	-0.462	0.170	Consumers Power
0.583	0.757	-0.291	0.117	East Ohio Gas
0.588	0.710	-0.178	0.055	Consolidated Edison
0.768	0.570	0.092	0.106	Niagra Mohawk
0.769	0.235	0.784	-0.250	Connecticut Natural Gas
0.776	1.070	-0.636	0.342	Pacific Gas & Electric
0.797	0.575	0.273	-0.051	Washington Natural Gas
0.813	1.130	-0.680	0.364	SOUTHERN CALIFORNIA GAS
0.817	0.482	0.499	-0.164	new Jersey Natural Gas
0.819	0.472	0.476	-0.129	People's Natural Gas
0.829	0.656	0.150	0.024	Questar (Mountain Fuel Supply)
0.833	0.842	-0.138	0.129	Atlanta Gas Light
0.848	0.229	0.844	-0.225	North Shore Gas
0.862	0.409	0.621	-0.167	Rochester Gas and Electric
0.871	0.372	0.655	-0.156	COMMONWEALTH GAS
0.886	0.519	0.408	-0.040	Peco (Philadelphia Electric)
0.914	0.603	0.320	-0.010	BALTIMORE GAS & ELECTRIC CO
0.931	0.755	-0.261	0.437	UNION GAS
0.944	0.579	0.317	0.048	Wisconsin Gas
0.971	0.196	1.080	-0.305	Madison Gas & Electric
1.010	0.504	0.524	-0.018	Illinois Power
1.018	0.437	0.693	-0.111	Louisville Gas and Electric
1.025	0.178	0.998	-0.150	Orange & Rockland Utilities
1.044	0.803	0.101	0.140	Southwest Gas
1.057	0.271	0.867	-0.081	Pg Energy (Penn Gas & Water)
1.066	0.268	0.967	-0.169	Connecticut Energy
1.083	0.549	0.471	0.063	Northwest Natural Gas
1.173	0.470	0.736	-0.033	Public Service of North Carolina
1.175	0.531	0.590	0.054	Alabama Gas
1.208	0.268	1.052	-0.111	Wisconsin Power & Light
1.278	0.020	1.470	-0.212	Central Hudson Gas
1.282	0.655	0.540	0.087	SAN DIEGO GAS & ELECTRIC
1.435	0.288	1.029	0.118	Cascade Natural Gas

EGD-14 output elasticities with full model GD.txt

RTS (sum of output elasticities) calculated at all data points

sum	yn	yvrc	yvoth	utility
0.279	0.716	-0.572	0.135	ENBRIDGE
0.349	0.756	-0.609	0.202	NICOR
0.409	0.619	-0.214	0.005	Peoples Gas Light
0.418	0.650	-0.080	-0.152	Washington Gas Light
0.460	0.721	-0.420	0.160	Public Service Electric & Gas
0.468	0.749	-0.446	0.165	Consumers Power
0.530	0.670	-0.259	0.118	East Ohio Gas
0.558	0.627	-0.132	0.063	Consolidated Edison
0.569	0.861	-0.620	0.329	Pacific Gas & Electric
0.575	0.888	-0.663	0.350	SOUTHERN CALIFORNIA GAS
0.758	0.749	-0.117	0.126	Atlanta Gas Light
0.815	0.575	0.134	0.106	Niagra Mohawk
0.855	0.646	0.182	0.026	Questar (Mountain Fuel Supply)
0.855	0.575	0.321	-0.041	Washington Natural Gas
0.861	0.671	-0.229	0.418	UNION GAS
0.927	0.512	0.560	-0.146	new Jersey Natural Gas
0.937	0.526	0.527	-0.115	People's Natural Gas
0.964	0.604	0.364	-0.004	BALTIMORE GAS & ELECTRIC CO
0.976	0.551	0.457	-0.032	Peco (Philadelphia Electric)
0.996	0.731	0.129	0.135	Southwest Gas
1.001	0.590	0.361	0.050	Wisconsin Gas
1.003	0.378	0.853	-0.227	Connecticut Natural Gas
1.012	0.480	0.682	-0.150	Rochester Gas and Electric
1.039	0.461	0.717	-0.139	COMMONWEALTH GAS
1.084	0.372	0.915	-0.203	North Shore Gas
1.110	0.544	0.577	-0.011	Illinois Power
1.155	0.564	0.525	0.066	Northwest Natural Gas
1.162	0.518	0.744	-0.100	Louisville Gas and Electric
1.243	0.375	1.150	-0.282	Madison Gas & Electric
1.258	0.555	0.646	0.057	Alabama Gas
1.276	0.421	0.927	-0.071	Pg Energy (Penn Gas & Water)
1.285	0.343	1.075	-0.133	Orange & Rockland Utilities
1.289	0.403	1.038	-0.152	Connecticut Energy
1.299	0.541	0.786	-0.028	Public Service of North Carolina
1.309	0.622	0.597	0.089	SAN DIEGO GAS & ELECTRIC
1.435	0.416	1.119	-0.100	Wisconsin Power & Light
1.624	0.250	1.564	-0.191	Central Hudson Gas
1.633	0.409	1.105	0.119	Cascade Natural Gas

Enbridge #15

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

In reference to the passage cited above at page 82 of the June 20, 2007 report, please estimate a full translog cost model, and provide;

a. All econometric estimates, and relevant statistics, such as standard errors in the same format as Tables 19A and 19B.

b. Please provide all programming code, spreadsheets, and data associated with the estimation of the full translog cost function.

c. Please provide all company-specific price elasticities, output elasticities, and rates of technological change for each year associated with this estimation.

RESPONSE

a. Please see the tables provided in 14.b.

b. Please see the answer provided for 14.a.

c. See the attached file EGD-15 elasticities CS full translog model.xls for the price and output elasticities, in the first worksheet, and for rates of technological change, in the second worksheet, by company and by year for the cost of service treatment of capital cost. See the attached file EGD-15 elasticities GD full translog model.xls for the price and output elasticities, in the first worksheet, and for rates of technological change, in the second worksheet, by company and by year for the geometric decay treatment of capital cost.

Please note that the output elasticities are markedly less plausible using the full translog models than using the restricted cost functions we featured in our June report. In the case of Enbridge (ID 58), for instance, we find using GD costing substantially negative elasticities with respect to the residential and commercial delivery volume. The sum of the output elasticities is below 0.4 each year. These estimates would have yielded a much higher TFP growth target than those obtained from the restricted cost function that we featured in our June report. A similar comparison obtains using COS costing. The results clearly indicate the unsuitability of the full translog model as a basis for company-specific output elasticities.

Enbridge #17

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please provide all computer code, spreadsheets, data and other work papers PEG relied on for its April 2007 testimony "Revised Prepared Direct Testimony of Mark Newton Lowry, Ph.D. on Behalf of Southern California Gas Company" in CPUC Docket No. A.06-12-010, and the accompanying report "TFP Research for Southern California Gas." The provided materials should be sufficient to replicate all results reported or discussed in the April 2007 testimony and report in CPUC Docket No. A.06-12-010. Please provide materials in usable electronic format. The response should include but not be limited to:

a. All data on U.S. utilities either used or considered for the April 2007 testimony and report.
b. The econometric cost model used for the April 2007 testimony and report.
c. The model, computer code or spreadsheet used to calculate capital cost in the April 2007 testimony and report.
d. The data and model code provided to the California PUC Division of Ratepayer Advocates (DRA) in CPUC Docket No. A.06-12-010.
e. The work papers of the California PUC Division of Ratepayer Advocates (DRA) in CPUC Docket No. A.06-12-010.

RESPONSE

PEG will not provide this information. PEG has not filed either of the referenced reports in this proceeding, nor has it relied on these documents to produce its report in the current proceeding before the Board. In addition to being irrelevant, the requested data are voluminous and would require substantial time and effort to assemble.

Witness: Mark Lowry

Enbridge #19

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

On page 7 of PEG's April 2007 revised report in CPUC Docket No. A.06-12-010, PEG states,

> "The regional coverage of sampled LDCs can be seen to be somewhat uneven. For example, California distributors accounted for almost 30% of the customers in the sample but for only 15% of U.S. gas end users. In contrast, the South Central states accounted for only 2% of the customers in the sample and for almost 9% of end users nationally. We have made a correction for this imbalance that is discussed further below."

Then, on page 19 of the June 20, 2007 report in EB-2007-0606/0615,

> "The regional distribution of sampled companies is uneven. For example, California utilities accounted for about 32% of the customers in the sample but for only 15% of all customers in the continental US. Utilities in the South Central States account for 2.5% of the customers in the sample but almost 15% of those in the continental US."

a. Please explain why there was an adjustment for the regional imbalances in the utility sample in CPUC Docket No. A.06-12-010, but not in the Ontario work.
b. Please comment on, and show the impact of, a similar adjustment for regional imbalances on the results reported in the June 20, 2007 report.

RESPONSE

a. The reason that the regional weightings were not used was because with the loss of Atmos, the Texas region had no data. Therefore, the methodology used in the Sempra work was no longer feasible. Note also that there was no need to calculate any size weighted and regionally adjusted estimate of the TFP trend of the U.S. gas distribution industry since we were not intending to use it as a TFP target in the calculation of the productivity differentials for Enbridge and Union. The average TFP trend of the U.S. gas distributors is mentioned in our June report but is also not recommended as a TFP target.

b. This adjustment cannot be made for the reasons stated.

Enbridge #20

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please provide all computer code, spreadsheets, data and other work papers relied upon in the March 30, 2007 report "Price Cap Index Design for Ontario's Natural Gas Utilities." The provided materials should be sufficient to replicate all results reported or discussed in the March 30, 2007 report. Please provide materials in usable electronic format. The response should include but not be limited to:

a. All data on U.S. utilities either used or considered for the March 30, 2007 report.
b. All data on Union or EGDI either used or considered for the March 30, 2007 report.
c. The model used to weather-normalize U.S. residential and commercial volumes, and Union and EGDI's residential and commercial volumes.
d. The econometric cost model.
e. The model, computer code or spreadsheet used to calculate input price differentials.
f. The model, computer code and/or spreadsheets used to calculate capital cost under both the GD and COS methodologies.

RESPONSE

a. The data used in the econometric work for the March 30, 2007 report is oebgas5.xls, which can be found in the working paper folder (3.2.1). All the same variables used in the June 20, 2007 report are used except the weather normalized residential & commercial deliveries. The weather normalization method used was different and the variable that it generated is called ayvrc, which was used in the March work.

Witness: Mark Lowry

The codes used to generate this model are also found in the working paper folder (3.2.2). In the main code (DR_TC), make y2 = ayvrc1 has to be changed to make y2 = ayvrc in line 62. In addition, in the file modeloeb.inc in line 41, the output interaction terms have to be included or 'uncommented' and the first value of novars in line 45 has to be changed to 27 from 24. Further, when computing the company specific elasticities, the terms y1y2 and y1y3, y1y2 and y2y3, and y1y3 and y2y3 have to be 'uncommented' along with the data values that go with them (lines 519-573 in the main code DR_TC).

b. We will provide this information shortly.

c. The model used to weather normalize U.S. residential and commercial volumes is EGD-20 wAdjout.txt, and it is generated by the code EGD-20 wAdjprg.txt using the data EGD-20 weathernorm2.xls. The weather normalized values for the U.S. companies are in EGD-20 wAdj.xls. The models, data and results for the weather normalization of EGDI's and Union's deliveries are found in the file EGD-20 March 20 weather norm.xls. (All the files are attached).

d. We will provide this information shortly.

e. We will provide this information shortly.

f. We will provide this information shortly.

Witness: Mark Lowry

```
******************************************************************************
                         GAUSS Data Import Facility
******************************************************************************

Begin import...
Import completed
Number of rows in input file:                          467.00000
Number of cases written to GAUSS data set:              466.00000
Number of missing elements:                            1332.0000
Number of variables written to GAUSS data set:          36.000000
       1.0000000

********************************************************************************

 Date:  5/31/07 ****    REGRESSION for WEATHER ADJUSTING VOLUME DATA   ****   Ti
me: 13:25:27

                        OUTPUT FILE:C:\work\Oebgas\results\wAdj2

                            DATA FILE:C:\work\Oebgas\weathernorm2.xls

********************************************************************************
       396.00000
                           OLS REGRESSION

Valid cases:                      360      Dependent variable:             GYVRC
Missing cases:                      0      Deletion method:                 None
Total SS:                       2.968      Degrees of freedom:               358
R-squared:                      0.300      Rbar-squared:                   0.298
Residual SS:                    2.079      Std error of est:               0.076
F(1,358):                     153.125      Probability of F:               0.000
Durbin-Watson:                  2.548

                         Standard                 Prob   Standardized  Cor with
Variable     Estimate      Error      t-value     >|t|     Estimate    Dep Var
-------------------------------------------------------------------------------
CONSTANT     0.008722    0.004017    2.171589     0.031       ---         ---
GFHDD        0.354618    0.028658   12.374361     0.000    0.547343    0.547343


                           OLS REGRESSION

Valid cases:                      360      Dependent variable:            GYVOTH
Missing cases:                      0      Deletion method:                 None
Total SS:                      32.054      Degrees of freedom:               358
R-squared:                      0.007      Rbar-squared:                   0.005
Residual SS:                   31.814      Std error of est:               0.298
F(1,358):                       2.699      Probability of F:               0.101
Durbin-Watson:                  2.306

                         Standard                 Prob   Standardized  Cor with
Variable     Estimate      Error      t-value     >|t|     Estimate    Dep Var
-------------------------------------------------------------------------------
CONSTANT    -0.026630    0.015713   -1.694739     0.091       ---         ---
GFHDD        0.184191    0.112113    1.642906     0.101    0.086505    0.086505


                           OLS REGRESSION

Valid cases:                      360      Dependent variable:            GYVRES
Missing cases:                      0      Deletion method:                 None
Total SS:                       3.253      Degrees of freedom:               358
R-squared:                      0.380      Rbar-squared:                   0.378
Residual SS:                    2.017      Std error of est:               0.075
F(1,358):                     219.463      Probability of F:               0.000
Durbin-Watson:                  2.702

                         Standard                 Prob   Standardized  Cor with
Variable     Estimate      Error      t-value     >|t|     Estimate    Dep Var
-------------------------------------------------------------------------------
CONSTANT     0.007817    0.003956    1.975949     0.049       ---         ---
GFHDD        0.418173    0.028228   14.814289     0.000    0.616480    0.616480


                           OLS REGRESSION
```

Valid cases:	360	Dependent variable:	GYVCOM
Missing cases:	0	Deletion method:	None
Total SS:	5.111	Degrees of freedom:	358
R-squared:	0.091	Rbar-squared:	0.088
Residual SS:	4.646	Std error of est:	0.114
F(1,358):	35.787	Probability of F:	0.000
Durbin-Watson:	2.417		

Variable	Estimate	Standard Error	t-value	Prob >|t|	Standardized Estimate	Cor with Dep Var
CONSTANT	0.010641	0.006005	1.772102	0.077	---	---
GFHDD	0.256304	0.042844	5.982230	0.000	0.301462	0.301462

Enbridge #21

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please provide all computer code, spreadsheets, data and other work papers PEG relied upon for DTE Docket No. 03-40, and the accompanying reports "X-Factor Calibration for Boston Gas" and "The Cost Performance of Boston Gas." The provided materials should be sufficient to replicate all results reported or discussed by PEG in DTE Docket No. 03-40. Please provide materials in usable electronic format. The response should include but not be limited to:

a. All data on U.S. utilities either used or considered for PEG's testimony and reports in DTE Docket No. 03-40.
b. The econometric cost model used for PEG's testimony and reports in DTE Docket No. 03-40.
c. The model, computer code or spreadsheet used to calculate capital cost in PEG's testimony and reports in DTE Docket No. 03-40.

RESPONSE

PEG will not provide this information. PEG has not filed either of the referenced reports in this proceeding, nor has it relied on these reports to produce its report in the current proceeding before the Board. In addition to being irrelevant, the requested data are voluminous and would require substantial time and effort to assemble.

Witness: Mark Lowry

Enbridge #22

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please provide all computer code, spreadsheets, data and other work papers PEG relied upon for the June 2004 report "New Zealand Natural Gas Distribution Cost Performance: Results from International Benchmarking" and the June 2004 report "Comments on Meyrick and Associates Reports Prepared for the Commerce Commission's Inquiry into New Zealand Gas Transmission and Distribution Sectors." The provided materials should be sufficient to replicate all results reported or discussed by PEG in these reports. Please provide materials in usable electronic format. The response should include but not be limited to:

a. All data on U.S. utilities either used or considered for PEG's June 2004 reports.
b. The econometric cost model used for PEG's June 2004 reports.
c. The model, computer code or spreadsheets used to calculate capital cost in PEG's June 2004 reports.

RESPONSE

PEG will not provide this information. PEG has not filed either of the referenced reports in this proceeding, nor has it relied on these reports to produce its report in the current proceeding before the Board. In addition to being irrelevant, the requested data are voluminous and would require substantial time and effort to assemble.

Witness: Mark Lowry

Enbridge #26

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

On page 36 of PEG's June 20, 2007 report, PEG states,

> "It should also be noted that PEG has long had difficulty identifying statistically any special impact on gas utility cost management that results from transmission and storage operations. There was for this reason no compelling need to take transmission and storage into account in choosing Union's peer group."

Please provide all support, including all computer code, spreadsheets, data, work papers and other documentation associated with any of the work performed, underpinning these statements.

RESPONSE

Details of this research will not be provided since it was undertaken in the past for other clients and documentation is spotty. Our recollection at the outset of this project is that we had tried over the years a number of indicators of transmission and storage activity in our cost models and found that the corresponding parameter estimates were generally either insignificant (not significantly different from zero) or significant but incorrectly signed. Based on this past experience, we tried in this project to capture the special cost impact of Union's transmission operations by having two volume variables in the cost model (residential & commercial deliveries and other deliveries) instead of one (total throughput) and by using company-specific output elasticities in the output quantity indexes and the TFP projections.

Witness: Mark Lowry

Enbridge #27

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

On page 25, of the June 20, 2007 report,

> "The incremental scale economies from output growth are even greater for large companies like Enbridge and Union than they are for smaller companies. This is due, apparently, to special economies in the delivery of volumes, which are characteristic of piping systems."

a. Please explain in detail what is meant by the phrase "special economies in the delivery of volumes, which are characteristic of piping systems."
b. Please provide any and all analyses PEG has undertaken related to "special economies in the delivery of volumes, which are characteristic of piping systems."

RESPONSE

a. "Special economies in the delivery of volumes" refer to the fact that the cost per unit of gas delivery volume is negatively related to the volume. In other words, the cost per dkt of gas distribution service declines as the volume of delivered gas increases. There is extensive support in the economic literature that these economies are inherent in the technology of gas delivery. Below are two quotes from published studies that support the existence, and describe the sources, of scale economies in the delivery of natural gas.

    1. "Gas pipelines exhibit significant economies of scale in both construction and operation. Up to a very large capacity, the per-mile cost of construction varies with the radius of a pipeline but the capacity varies with the square of the radius. Per-unit operating costs also decline with increased volumes. Therefore, the construction and operating costs of one pipeline are usually lower than the costs of two parallel pipelines each transporting

half as much gas." [Bernhardt, J. (Feb. 1998), "Is Natural Gas Pipeline Regulation Worth the Fuss?," *Stanford Law Review 40*(3), pp. 757-758]

2. "(One of the) basic facts of nature (are the)…powerful economies of scale in pipeline transmission…pipelining is a classic example of scale economies and local 'natural monopoly.' The capital costs of a line, given the terrain, are less than directly proportional to the amount of steel needed, since right of way and installation costs vary little with line diameters. Steel requirements are proportional to nearly the square of the diameter (therefore of the radius) of the line. Operating cost is a matter of overcoming the friction of the fluid against the inside of the pipe; the friction is directly proportional to radius. But the output of the line, i.e. the amount of oil or gas which can be carried in a given period, is more than proportional to the cross section area, i.e. to more than the square of the radius.1 Hence a 36-inch pipeline may be expected to cost rather more *than* twice as much as an 18-inch line, but to carry substantially more than four times as much, so that the unit cost is about half (see below, Table 111, p. 49). Even if the amount of available gas is greater than can be carried most economically in the 36-inch line, it is usually cheaper to increase pressure and pay to overcome the additional friction with additional compressor stations than to build, say, two 24-inch lines." [Adelman, M.A. (1962), ,"The Price of Natural Gas Reserves. *The Journal of Industrial Economics, Vol. 10 Supplement: The Supply and Price of Natural Gas*, pp. 44-45].

b. Our research has supported the notion of special volumetric economies chiefly through our econometric estimates of the elasticities of cost with respect to output. We conventionally use translog functional forms in our statistical cost research, and have generally found that the quadratic volumetric term has a sign that is either negative or, if positive, is close to zero. Low values for this elasticity estimate has the indirect result that the sum of the output elasticities, a standard measure of the existence of incremental scale economies, is well below 1 at sample mean levels of the output variables. This means that there are substantial incremental scale economies available from output growth for firms of average size. When this condition holds, companies with operating scales well *above* the mean can still earn incremental scale economies from output growth. For firms that, like Enbridge, have rapid output growth, this can contribute materially to TFP growth. Please note that we do not find this result in our power distribution research.

Below we produce the key results for all eleven gas distribution econometric cost studies that PEG has published in the last decade that we still have suitable records of. For each study we list:

- The name of the client (SDG&E is San Diego Gas and Electric, SoCalGas is Southern California Gas, Multinet is a gas distributor in Victoria, Australia, and 'New Zealand' applies to two NZ gas distributors: Vector and NGC)
- The date of the study
- Whether the study benchmarked or analyzed total gas distribution cost (TC) or operating and maintenance costs (O&M)
- The coefficient on the quadratic term for gas deliveries (VV)
- The t-statistic associated with the coefficient on the quadratic term for gas deliveries
- The sum of the estimated output elasticities at the sample mean level of output.

Client	Date	Costs	VV Coefficient	VV T Stat	Sum Output Elasticity
SDG&E	1/98	TC	.010	0.13	.755
Multinet	9/01	O&M	-.125	-0.52	.843
SoCalGas	12/02	TC	-.487	-4.17	.855
Enbridge	1/03	O&M	-.395	-3.50	.875
Boston Gas	4/03	TC	-.512	-6.83	.868
SDG&E	2/04	TC	-.365	-2.62	.928
Enbridge	2/04	O&M	-.440	-2.72	.944
New Zealand	6/04	TC	-.085	-1.17	.688
Bay State	4/05	O&M	-.054	-0.36	.612
SDG&E	8/06	TC	-.041	-0.05	.867
ESC	6/07	O&M	0.17	0.14	.767

It can be seen that the coefficient on the quadratic term for deliveries was negative in nine of the 11 applications and this coefficient was statistically significant in five of those nine studies. The estimate was not found to be positive and statistically significant in any study. Please note that all of these studies involved fully translogged output specifications. We also find that incremental scale economies exist at the sample mean in each of the studies, with an average for the sum of the output elasticities equal to .818. This means that 1% growth in all output variables raises cost by only 0.818%.

Overall, our research supports the conclusion that growth in gas distribution output (particularly growth in gas deliveries) can produce scale economies even for large companies like EGDI. Since, additionally, incremental scale economies can be an important source of TFP growth, our research also shows that the growth in gas distribution output is an important criterion for selecting an appropriate TFP growth peer group for EGDI. These findings argue against the use of a northeast peer group for Enbridge since output growth is much slower in the northeast than in metropolitan Ottawa and Toronto.

Enbridge #29

INTERROGATORY

Ref: Econometric Cost Model and Productivity Differential

Issue Number:
Issue:

Please provide PEG's TFP growth projections for Enbridge and Union based on the GD and COS approaches to capital input price measurement, as in Table 10, for each of the years 2000, 2001, 2002, 2003, 2004, and 2005. Provide the data, programming code, and spreadsheets.

RESPONSE

Please see the working papers folder (3.2) for the programming code (DR_TC is the main one) and data used to generate the parameter estimates used in developing TFP projections for Enbridge and Union for each of the years. These TFP projections for the years 2000 to 2005 can be found in the attached file TFP Projections by year Enbridge and Union.xls.

Witness: Mark Lowry

Enbridge #40

INTERROGATORY

Ref: Input Price Differential

Issue Number:
Issue:

Please calculate U.S. economy input price index and growth rates for each year over the period 1994-2004 in the same manner as PEG calculated the Canadian input price indices and growth rates in Table 14. Provide all data, programming code and spreadsheets.

RESPONSE

See the attached worksheet entitled Q40 attachment. Please note that we used the latest available data to make this calculation. Had we used the data from the report, the input price trend would have been 0.03% higher.

Witness: Mark Lowry