International Journal of Energy Economics and Policy

ISSN: 2146-4553

available at http: www.econjournals.com

International Journal of Energy Economics and Policy, 2015, 5(3), 686-692.

Texas Interconnection Grid: Economic Optimal Capacity Utilization Rate Evidence

Eric L. Prentis*

School of Accounting and Finance, Wenzhou-Kean University, Wenzhou, China. *Email: eric.prentis@gmail.com

ABSTRACT

For the first time in the literature, the supply and demand model, with 2011-2014 data, is used to analyze the Texas Interconnection grid electricity market. The electric utility industry's production function, fixed, variable and total cost (TC) curve represents the supply curve. The demand curve is the electricity price in the assumed perfectly competitive electricity market. The efficient scale of production is established—located where the U-shaped average TC curve reaches a minimum—and using marginal analysis, where marginal revenue equals marginal cost, to determine the economic optimal capacity utilization rate that maximizes electric utility industry profits. This paper's aggregate results on the economics of the electric utility market are meaningful, insightful and well-timed—having important electric utility policy implications.

Keywords: Economic Optimal Capacity Utilization Rate, Efficient Scale of Production, Capacity Planning. Electric Utility Policy
JEL Classifications: G31, G38, H44, K23

1. INTRODUCTION

Capacity utilization is a short-term, output-based measure of the intensity with which the overall economy, individual industries or specific firms actually operate their installed productive capacity, over a specified period—conditional on a given state of technology, a fixed stock of capital and variable input costs. For example, U.S. capacity utilization is the "operating rate" of the nation's industrial capacity, which is a fundamental measure frequently used to evaluate aggregate demand or resource constraints for the U.S. economy. The U.S. Federal Reserve's Federal Open Market Committee (FOMC) studies the U.S. capacity utilization rate, in addition to other variables, when judging the strength or weakness of the U.S. economy—which the FOMC then uses to set the federal funds interest rate.

Capacity utilization is an indicator of either excess capacity or inflationary pressures in the U.S. economy. Over the long-term, the U.S. stable-inflation industrial capacity utilization rate remains constant at 82% (Garner, 1994), (Corrado and Mattey, 1997). Throughout the business cycle, as market demand increases during an economic expansion, the nation's industrial productive capacity may be strained and over-utilized, rising above a capacity utilization rate of 82%, which is potentially inflationary—and as market demand falls during a recession, the nation's industrial productive capacity may be excessive and underutilized, falling below a capacity utilization rate of 82%, which is potentially deflationary.

The Federal Reserve (2014) reports the nation's industrial capacity utilization rate, seasonally adjusted, averages 80.1%, from 1972 to 2013, and reaches a high of 85.3% in 1989 and a low of 66.9% in 2009. There are considerable variations in actual capacity utilization rates across different industries and during specific times. For example, capacity utilization for the U.S. electric utility industry, seasonally adjusted, averages 76.1%, during the summer months of June, July and August of 2014.

The goal of this research, using the supply and demand model, with 2011-2014 data, is to analyze the Texas Interconnection grid electricity market, for which the independent system operator (ISO) is the Electric Reliability Council of Texas (ERCOT). The electric utility industry's production function, fixed, variable and total cost (TC) curve represents the supply curve. The demand curve is the price of electricity in the assumed perfectly competitive electricity market. The efficient scale of production is established—located where the U-shaped average TC (ATC) curve reaches a minimum—and using marginal analysis, where marginal revenue (MR) equals marginal cost (MC), to determine the economic optimal capacity utilization rate that maximizes electric utility industry profits. This paper's aggregate results on the economics of the electric utility market are meaningful, insightful and well-timed—having important electric utility policy implications.

This paper's organization is as follows: Section 2 discusses the literature relevant to U.S. capacity utilization and the Texas Interconnection grid electricity market. Section 3 presents the government and industry sources of the data used in this study, and the supply and demand model employed to analyze the production function's fixed, variable and TCs, and revenue. Section 4 explains the empirical results. Section 5 discusses the relatively flat ATC curve, capacity planning and the long-run ATC (LRATC) curve. Section 6 presents concluding comments and policy implications.

2. LITERATURE REVIEW

Berndt and Morrison (1981) explain the division of TC—between fixed and variable costs (VCs)—is determined based solely on the time horizon. Capacity utilization is a short-term concept, conditional upon quasi-fixed inputs in the short run, but obtainable at increasing MCs—in the long run. Nelson (1989) defines the measurement of capacity utilization as the ratio of actual to the maximum potential or design output, consistent with a given capital stock. An economic methodology is used to determine potential output, based on capacity utilization measures, which are conditional upon economic factors.

Ray et al. (2006), for the period 1970-2001, computes capacity utilization measures for a number of U.S. industries, as well as U.S. manufacturing overall. The authors report considerable variation in actual capacity utilization rates, across the different industries and during specific times. Nikiforos (2013) examines long-term normal capacity utilization, based solely on internal factors within the firm. A cost-minimizing or profit-maximizing firm, with decreasing returns to scale, wants to increase its capacity utilization. For example, by adopting a double-shift production schedule that pays a premium wage, as the firm's demand increases.

Bernstein Research (2010) studies the reasons why China's electric utilities report seemingly excess capacity utilization rates, while at the same time experiencing sustained load shedding events that severely disrupt their industrial sector. In the 1980s, China operates her electric generators in the low-70% "net capacity factor" range, in the 1990s in the mid-60% range, and about 50% of "net capacity factor" range, from 2000 to 2009. The continuing long-term decline in "net capacity factor" utilization rates seems paradoxical, because electricity shortages in China have become progressively more chronic.

Prentis (2014a) tests whether ERCOT is accomplishing its stated mission, which is to achieve electrical system efficiency and reliability. A statistical test of electricity prices on the Texas Interconnection grid, relative to U.S. electricity prices, is used to test efficiency. North American Electric Reliability Corporation (NERC) alerts are used to determine system reliability. Sioshansif and Tignor (2012) establish when ISO/regional transmission organizations make commitment and dispatch decisions that schedules which different company's power plants are to be brought online—they do so by solving for locational marginal pricing, which are non-convex NP-hard mixed-integer algorithms.

The Brattle Group (2014) prepares a report for ERCOT to determine reserve margins, by balancing the costs of constructing new generating plants versus costs of not having enough capacity to meet peak demand, resulting in rotational load shedding and other emergency events. Based on a risk-neutral, probability-weighted average cost, using 7500 simulations, the minimum system capital and production cost occurs at a reserve margin of 10.2%. The reserve margin increases to 14.1%, to meet the target U.S. industry standard of 0.1 loss-of-load event/year.

Prentis (2014b) tests whether U.S. electrical system reliability standards are being maintained and if states are adding sufficient generating capacity to meet demand, and therefore, maintain high electrical system reliability, when compared to the U.S., overall. Four of the six NERC U.S. assessment areas are falling below NERC reference reserve margin standards and are thought to be unreliable. As a whole, the 18 NERC U.S. assessment areas stay above the NERC reference reserve margin standard. Prentis (2015) reports on the 11 states and the District of Columbia that have increased electricity prices—relative to U.S. electricity prices—over four times faster than the U.S. average.

3. DATA AND METHODOLOGY

ERCOT (2014a) publishes the "Demand and Energy (% by fuel type of energy by month)" for the Texas Interconnection grid, which lists the energy by fuel type and percentages for each fuel type used, during the peak summer months of June, July and August of 2014. Energy by fuel type and their average percentages for the 2014 summer months are presented in Table 1 and shown in column (1): by fuel type; and in column, (2): fuel type percent (%).

ERCOT (2014b) publishes the "Resource Adequacy Assessments: Capacity, Demand and Reserves Report: Summer Capacities," listing the types of electric power generating plants powering the Texas Interconnection grid. The names of the ERCOT plant types are listed in Table 1, column (1): below each fuel type. For example, natural gas fuel is used in conventional combined cycle and combustion turbine power plants for 44.8% of the generating capacity needed to meet ERCOT's electricity demand during the summer of 2014.

The U.S. Energy Information Administration (EIA) (2013a) presents in their Table 1. Capital Costs for Electricity Plants: Updated Estimates of Power Plant Capital and Operating Costs—the updated overnight generation capital cost estimates for new utility-scale electricity generating plants, for a generic U.S. location, without any special considerations that would modify

Table 1: Overnight generation installed capital costs and construction schedules

(1) By fuel type: Plant type	(2) Fuel type percent	(3) Nominal capacity in MW	(4) Overnight capital and fixed O and M costs ($/kW)	(5) ERCOT region cost adjust percent	(6) Weighted average overnight capital costs ($/kW)	(7) Weighted average constuction schedules (months)
Natural gas	44.8					
Conventional combined cycle (64%)[1]		620 MW	$930.17	0.91	$242.69	11.76
Conventional combustion turbine (36%)		85 MW	$980.34	0.93	$147.04	4.84
Coal						
Single unit advanced pulverized coal	34.6	650 MW	$3,283.80	0.91	$1,033.94	19.03
Nuclear						
Dual unit nuclear	10.8	2,234 MW	$5,623.28	0.96	$583.02	6.48
Wind						
Onshore wind (84%)[2]	8.6	100 MW	$2,252.55	0.95	$154.59	0.87
Offshore wind (16%)		400 MW	$6,304.00	0.92	$79.80	0.17
Water						
Conventional hydroelectric	0.1	500 MW	$2,950.13	1.00	$2.95	0.02
Other						
Biomass-bubbling fluidized bed (50%)[3]	1.1	50 MW	$4,219.63	0.93	$21.58	0.20
Solar-photovoltaic (50%)		150 MW	$3,897.69	0.87	$18.65	0.01
				Total	$2,284.26	43.38

[1]The natural gas plant types percentages are determined by counting the number of Conventional Combined Cycle and Conventional Combustion Turbine plants in ERCOT's Capacity, Demand and Reserves Report - May 2014 (ERCOT, 2014b), [2]The onshore and offshore percentages are reported as installed onshore capacity of 10,340 MW and offshore capacity of 1,915 MW in the 2012 ERCOT Loss of Load Study Results (ECCO International, 2013), [3]The Biomass and Solar percentages are reported in the ERCOT Report on the Capacity, Demand, and Reserves in the ERCOT Region (ERCOT, 2014c). MW: Megawatts, $/kW: Dollars per kilowatt, ERCOT: Electric Reliability Council of Texas, O and M: Operations and maintenance

its cost. Plant characteristics by electricity generating plant type, nominal capacity in megawatts (MW), overnight capital cost in dollars per kilowatt ($/kW)—which includes fixed non-fuel operations and maintenance (O and M) costs—are presented in Table 1, column (3): nominal capacity in MW, and in column (4): overnight capital and fixed O and M costs, in $/kW.

The U.S. Energy Information Administration (EIA) (2013a) reports in their table on "Capital Costs for Electricity Plants: Regional Cost Adjustments for Technologies Modeled by NEMS by Electric Market Module (EMM) Region"—that constructing generating plant costs vary depending on the remoteness or congestion of U.S. plant locations, different plant seismic designs, and by labor productivity and wage differentials. These cost adjustment percentages for the ERCOT Texas Interconnection grid region are shown in Table 1, column (5): ERCOT Region Cost Adjustment Percent.

The weighted average overnight capital costs for each plant type, in $/kW, are reported in Table 1, and listed in column (6): weighted average overnight capital costs ($/kW)—which are calculated by multiplying the plant type percentage times the fuel type percentage times the overnight capital and fixed O and M costs, in $/kW, times the ERCOT region cost adjustment percent. For example: ERCOT's natural gas: conventional combined cycle plant's weighted average overnight capital costs, in $/kW, are: (64%) × (44.8%) × ($930.17/kW) × (0.91) = $242.69/kW. The weighted overnight capital costs for all plant types, in the ERCOT region, totals $2,284.26/kW, in $/kW—or in dollars per megawatt ($/MW), $2,284,260/MW.

Black and Veatch (2012) prepares the "Cost and Performance Data for Power Generation Technologies" report for the National Renewable Energy Laboratory that includes construction schedule performance data. The weighted average construction schedules for each plant type, in months, are presented in Table 1, column (7): weighted average construction schedules (months)—and are calculated by multiplying the plant type percentage times the fuel type percentage times the months required for construction. For example: ERCOT's natural gas: conventional combined cycle plant's weighted average construction schedule, in months, is: (64%) × (44.8%) × 41 months = 11.76 months. The weighted average construction schedules, for all plant types in the ERCOT region, totals 43.38 months, or 3.62 years.

Financing costs, necessary while power plants are under construction, are added to the overnight generation installed capital costs. The 7% per year weighted average cost of capital is multiplied times the weighted average construction schedule of 3.62 years, times the total weighted average overnight capital costs, in $/MW:—i.e. (7%/year) × (3.62 years) × ($2,284,260/MW) = $578,831/MW, representing financing costs. Overnight capital and financing costs, in $/MW, totals: $2,284,260/MW + $578,831/MW = $2,863,091/MW. The useful life of the power plants average 30 years, and the number of hours in 30 years is 262,800 h. The overnight capital and financing costs, in $/MWh, totals $2,863,091/MW, divided by 262,800 h, equals $10.8946/MWh.

The cost of generating electricity is only the largest factor in the TC of supplying electricity to consumers. The U.S. EIA (2013b) explains in "Factors Affecting Electricity Prices" that using and maintaining the transmission and distribution system—where costs are almost exclusively fixed costs (FCs)—to provide electricity from the generating plants to consumers, represents 42% of the TC, and electrical generation represents 58% of TC. Consequently, generation overnight capital and financing costs, and transmission and distribution costs, in $/MWh, totals $10.8946/MWh, divided by 58%, equaling $18.7838/MWh, which represents the fixed generation capital and financing costs, and transmission and distribution costs, in $/MWh, for the Texas Interconnection grid.

U.S. EIA (2012a) produces a hypothetical electric generator dispatch curve, for the summer 2011, that represents electric generators' variable operating costs, in $/MWh, for a system able to meet total electrical demand of 125,000 MW, which is shown in Figure 1. ERCOT (2014b) publishes the "Resource Adequacy Assessments: Capacity, Demand and Reserves Report: Summer Summary" and lists generating plant total resources, expected for 2015, at 77,051 MW. It is assumed the Texas Interconnection grid size information is scalable up to 125,000 MW, for comparison purposes. Consequently, while this dispatch curve does not represent an actual power system, it is a good approximation of the Texas Interconnection grid.

Electric power generators' variable operating costs are a major determinant in which power plants are dispatched to meet electricity demand. Those with the lowest variable operating costs, such as renewable wind generators and nuclear power plants, meet base-load demand, and accordingly, are dispatched first. Peaking units with higher VCs—such as natural gas combustion turbine and petroleum power plants—are brought into service, successively, by variable price, depending on increasing electricity demand. The sequence is shown in Figure 1, which specifies the expected order power plants are dispatched to meet electrical demand for the Texas Interconnection grid.

The dispatch curve's total system capacity available to meet electric demand equals 125,000 MW. The fixed generation capital and financing, transmission and distribution costs, in $/MWh, for the Texas Interconnection grid equals $18.7838/MWh. Therefore, FCs for the Texas Interconnection grid, in dollars per hour ($/h) are: (125,000 MW) × ($18.7838/MWh) = $2,347,975/h.

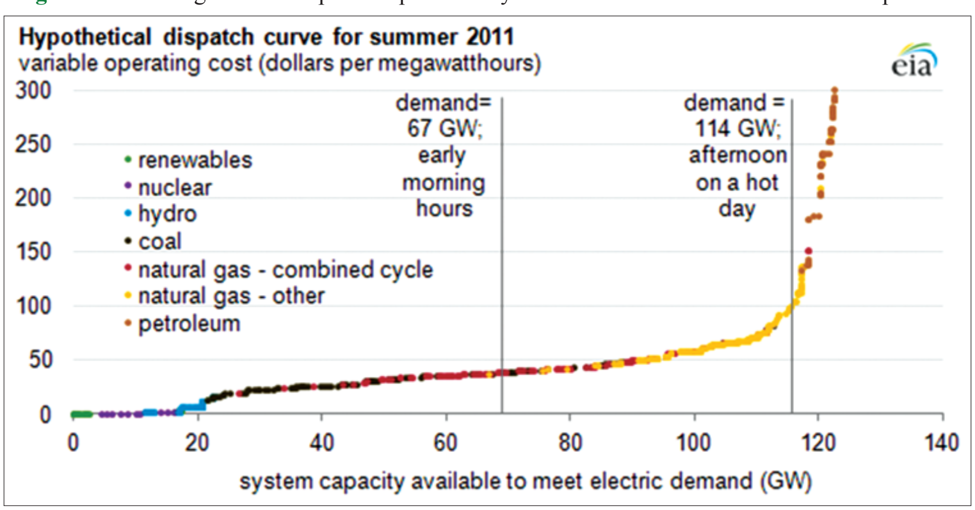
The Texas Interconnection grid electricity market evidence, using data from 2011 to 2014, is tested by applying the standard economics text-book supply and demand model (Mankiw, 2014), (Krugman et al., 2013), which uses the electric utility industry's production function, fixed, variable and TC curve, and assumed perfectly competitive electricity market prices. The efficient scale of production is determined, and the economic optimal capacity utilization rate is found that maximizes industry profits for the Texas Interconnection grid electricity market. The supply and demand model results are used to analyze long-term production decisions, based on costs and prices that are dependent upon market conditions.

TC is comprised of fixed and VCs. TC, divided by the quantity of output, equals ATC. The Texas Interconnection grid's efficient scale of production corresponds to the electricity production level that minimizes ATC, which is also at the point on the ATC curve where ATC equals MC. The ATC curve has two opposing effects, producing its U-shape—the "spreading effect," where an increased level of production reduces average FCs, and the "diminishing returns effect," where average VCs increase, with increasing output.

It is assumed the Texas Interconnection grid is a perfectly competitive market. The Texas Interconnection grid has many electricity generating suppliers, all producing one common commodity—electricity—which is regarded by consumers as equivalent, when choosing their retail electricity provider. Consequently, in a perfectly competitive electricity market, all electricity generating producers and consumers are price takers. Profit equals total revenue (TR)—which is calculated by multiplying market price (P) times quantity of output (Q)—less TC.

The profit-maximizing level of electricity output, using the producer's "optimal output rule" is producing the amount of electricity where MR equals MC. In a perfectly competitive Texas Interconnection grid electricity market, where all generators are price takers, the profit-maximizing quantity of electricity output is where market price (P)—which is also MR—equals MC. The U.S. EIA (2012b) reports in "Electric Sales, Revenue, and Average

Figure 1: Electric generator dispatch depends on system demand and the relative cost of operation



Source: U.S. Energy Information Administration (2012a). The X-axis, system capacity available to meet electric demand,is in gigawatts

Price" the total price for electricity in the Texas Interconnection grid market is, in cents per kWh, 8.55 cents/kWh, or in $/MWh, $85.50/MWh.

4. EMPIRICAL RESULTS

The range of electrical output, in MW, is from zero to 125,000 MW, and is located in Table 2, and shown in column: (1) output in MW. Capacity utilization, defined as: (actual output ÷ design output) × 100%, where 100% indicates full capacity utilization, is shown in Table 2, column, (2) capacity utilization percentage (%). Fixed generation capital and financing, transmission and distribution costs for the Texas Interconnection grid, in $/h, are calculated by multiplying 125,000 MW times $18.7838/MWh, and totals $2,347,975/h, which is listed in Table 2, column, (3) FC.

VCs are calculated using the U.S. EIA (2012a) electric generator dispatch curve shown in Figure 1. The average VC, in a production output range, is used to calculate the VC, in $/h, shown in Table 2, column (4): VC. TC in Table 2, column (5), equals FC plus VC, which is the sum of Table 2 columns (3) and (4), for each row.

ATC, in $/MWh, presented in Table 2, column (6), is calculated by dividing TC, Table 2, column (5), by the quantity of electricity produced—listed in Table 2, column (1): Output in MW, for each row. The ATC curve is U-shaped, reaching a minimum cost of $51.26/MWh.

MC, in $/MWh, is the amount by which the last $/MWh of electricity produced increases TC, at the production level identified in Table 2, column (1): Output in MW. The MC curve crosses the ATC curve, from below, at the minimum ATC, which is $51.26/MWh. Consequently, 92,000 MW is the quantity of production that minimizes ATC, which is equal to the efficient scale of production electricity output percentage of 74%, for the Texas Interconnection grid.

Production and profits shows electricity output (Table 3), in MW, in column (1), and the corresponding capacity utilization rate percentages, in column (2). Producers and consumers are price takers, in the perfectly competitive Texas Interconnection grid market. Consequently, TR, in $/h, shown in Table 3, column (3), is calculated by multiplying the $85.50/MWh total price of electricity times the electricity being produced, shown in Table 3, column (1), for each level of production.

TC for each level of production, listed in Table 3, column (4), transfers the TC figures calculated in Table 2, column (5). Profits (P) equal TR minus TC, in $/h, and are listed in Table 3, column (5), for each level of production. MC for each level of production, from Table 2, column (7), is transferred to column (6), in Table 3. In a perfectly competitive market, the total price of $85.50/MWh is equal to MR, which is a horizontal line for all production outputs, and is listed in Table 3, column (7): MR ($/MWh).

To maximize profits using marginal analysis, the "optimal output rule" says to produce the quantity of electricity where MC is equal to MR. This occurs at a production output level of 112,000 MW, corresponding to a 90% capacity utilization rate, which is the economic optimal capacity utilization rate that maximizes profits for the electric utility industry.

5. DISCUSSION

This supply and demand model study presents many meaningful insights. The U-shaped ATC curve, for the Texas Interconnection grid, is relatively flat around its minimum cost of $51.26/MWh. Outputs from 80,000 MW to 100,000 MW have ATCs less than +1.5% higher than the minimum ATC. Consequently, low-cost production stretches from 64% to 80% capacity utilization. Therefore, the amount of "excess capacity" in the Texas Interconnection grid may not be a critical issue. In addition, these

Table 2: Production function cost curves

(1) Output in MW	(2) Capacity utilization percentage	(3) FC ($/h)	(4) VC ($/h)	(5) TC=FC+VC ($/h)	(6) ATC ($/MWh)	(7) MC ($/MWh)
10,000	8	$2,347,975	$2,500	$2,350,475	$235.05	—
20,000	16	$2,347,975	$52,500	$2,400,475	$120.02	$10.00
30,000	24	$2,347,975	$202,500	$2,550,475	$85.02	$20.00
40,000	32	$2,347,975	$422,500[1]	$2,770,475	$69.26	$24.00
50,000	40	$2,347,975	$697,500	$3,045,475	$60.91	$31.00
60,000	48	$2,347,975	$1,032,500	$3,380,475	$56.34	$36.00
70,000	56	$2,347,975	$1,407,500	$3,755,475	$53.65	$39.00
80,000	64	$2,347,975	$1,812,500	$4,160,475	$52.01	$42.00
85,000	68	$2,347,975	$2,028,750	$4,376,725	$51.49	$46.00
90,000	72	$2,347,975	$2,272,500	$4,620,475	$51.34	$50.00
92,000	74	$2,347,975	$2,368,000	$4,715,975	$51.26	$52.00
100,000	80	$2,347,975	$2,822,500	$5,170,475	$51.70	$60.00
110,000	88	$2,347,975	$3,497,500	$5,845,475	$53.14	$75.00
120,000	96	$2,347,975	$4,997,500	$7,345,475	$61.21	$225.00
125,000	100	$2,347,975	$6,310,000	$8,657,975	$69.26	$300.00

FC and VCs in Table 2 are opportunity costs, which are assumed to include implicit and explicit costs. [1]The average VC, in a production output range, is used to calculate the VC, in $/h. For example, the average variable production cost between the output range of 30,000-40,000 MW is $22.00. VCs for this additional 10,000 MW of output are: 10,000 MW×$22.00=$220,000, which is added to the total VC of $202,500, at output of 30,000 MW, equaling $422,500, and is shown in column (4), for the production output of 40,000 MW. FC: Fixed costs, VC: Variable costs, TC: Total cost

Table 3: Production and profits

(1) Output in MW	(2) Capacity utilization percentage	(3) TR ($/h)	(4) TC=FC+VC ($/h)	(5) Profit (P) P=TR–TC ($/h)	(6) MC ($/MWh)	(7) MR ($/MWh)
10,000	8	$855,000	$2,350,475	−$1,495,475	—	$85.50
20,000	16	$1,710,000	$2,400,475	−$690,475	$10.00	$85.50
30,000	24	$2,565,000	$2,550,475	$14,525	$20.00	$85.50
40,000	32	$3,420,000	$2,770,475	$649,525	$24.00	$85.50
50,000	40	$4,275,000	$3,045,475	$1,229,525	$31.00	$85.50
60,000	48	$5,130,000	$3,380,475	$1,749,525	$36.00	$85.50
70,000	56	$5,985,000	$3,755,475	$2,229,525	$39.00	$85.50
80,000	64	$6,840,000	$4,160,475	$2,679,525	$42.00	$85.50
85,000	68	$7,267,500	$4,376,725	$2,890,775	$46.00	$85.50
90,000	72	$7,695,000	$4,620,475	$3,074,525	$50.00	$85.50
92,000	74	$7,866,000	$4,715,975	$3,150,025	$52.00	$85.50
100,000	80	$8,550,000	$5,170,475	$3,379,525	$60.00	$85.50
110,000	88	$9,405,000	$5,845,475	$3,559.525	$75.00	$85.50
112,000	90	$9,576,000	$5,998,475	$3,577,525	$85.50	$85.50
120,000	96	$10,260,000	$7,345,475	$2,914,525	$225.00	$85.50
125,000	100	$10,687,500	$8,657,975	$2,029,525	$300.00	$85.50

TC production numbers are opportunity costs, and assumed to include implicit and explicit costs. Consequently, the profit numbers calculated in Table 3 are economic profits, FC: Fixed costs, VC: Variable costs, TC: Total cost

results are interdisciplinary, supporting both engineering and operations in facility design.

Engineers design plants to operate at the best operating level—maximizing production output while minimizing wear and the required maintenance on the plant, because of overutilization. Operations require a flexible input-into-output transformation process, to meet changing customer, vendor, labor, regulatory, weather and competitor demands. From an engineering and operations standpoint, the best "operating rate" is a 70% of capacity utilization rate (Stevenson, 2014)—which is also close to the efficient scale of production capacity utilization rate of 74% calculated for the Texas Interconnection grid, and presented in this economic research.

Capacity utilization is a short-term concept, whereas capacity planning is strategic. For the Texas Interconnection grid, the weighted average construction schedule is 3.62 years. Environmental studies, government permits, engineering design, procurement and arranging for financing will increase the time required to bring a power plant online.

Capacity planning necessitates accurately forecasting long-term changes in demand, changes in government and environmental regulations, changes in technology, changes in product and process design, changes in the labor force, and changes in facility location or the supply chain—and then matching these multi-factor forecasts to expected long-term supply (Prentis, 1987). Evaluating alternatives requires understanding companies' quantitative as well as qualitative attributes. These include economic factors, management's strengths and weaknesses, and public opinion. Key capacity planning decisions are the types, size and when plants will be brought online to meet expected demand.

Capacity planning choices determine the U-shaped LRATC curve, where all costs, going forward, are VCs. FCs that minimize the U-shaped LRATC curve are the efficient scale of production, for each level of output (Nelson, 1989). Over the long run, there is a trade-off between fixed and VCs. Higher FCs will lower VCs, and vice versa, for a given level of output, with the determination made based on the confidence in the multi-factor forecasts (Krugman et al., 2013).

ERCOT sets the excess capacity reserve margin at 13.75%, to insure electrical system reliability. Therefore, the economic optimal capacity utilization rate of 90%, that maximizes electric utility industry profits, may result in an electrical system that is not reliable, because it is operated at too high a capacity utilization rate—over the long run. Therefore, FCs should be increased, during capacity planning, thus smoothing out the level of production, to lower the point on the LRATC curve, at higher production outputs.

6. CONCLUSIONS AND ELECTRIC UTILITY POLICY IMPLICATIONS

The goal of this research, using the supply and demand model, with 2011-2014 data, is to analyze the Texas Interconnection grid electricity market. ERCOT, U.S. EIA and Black and Veatch are the sources for data used to calculate FCs, in $/MWh, of $18.7838/MWh, VCs between $0-and-$300/MWh, and revenue of $85.50/MWh, for the Texas Interconnection grid.

For the first time in the literature, Texas Interconnection grid evidence, using 2011-2014 data, determines the grid's efficient scale of production—where the U-shaped ATC curve reaches a minimum of $51.26/MWh—corresponding to the efficient scale of production capacity utilization rate of 74%, which is close to the interdisciplinary engineering and operations preferred capacity utilization rate of 70%.

The less than +1.5% cost variation from the minimum ATC of $51.26/MWh, for the Texas Interconnection grid, extends from 64% to 80% capacity utilization—demonstrating that "excess capacity" may not be a critical issue when performing capacity planning. Using marginal analysis, where MR equals MC, the economic optimal capacity utilization rate of 90%, maximizes electric utility industry profits.

ERCOT sets the excess capacity reserve margin at 13.75%, to insure electrical system reliability. Therefore, the economic optimal capacity utilization rate of 90%, that maximizes electric utility industry profits, may result in electrical system that is not reliable, over the long run, because it is operated at too high a capacity utilization rate. In the long run, there is a trade-off between fixed and VCs. Higher FCs will lower VCs, and vice versa. Therefore, FCs should be increased, during capacity planning, thus smoothing out the level of production, to lower the point on the LRATC curve, at higher production outputs. This paper's aggregate results on the economics of the electric utility market are meaningful, insightful and well-timed—having important electric utility policy implications.

REFERENCES

Berndt, E.R., Morrison, C.J. (1981), Capacity utilization measures: underlying economic theory and an alternative approach. American Economic Review, 71(2), 48-52.

Bernstein Research. (2010). Black Book – Chinese Utilities: turn On the Lights, the Party's Over: understanding China's Utilization Rates and Power Outages. N.Y: Bernstein Global Wealth Management.

Black and Veatch. (2012), Cost and Performance Data for Power Generation Technologies: Prepared for the National Renewable Energy Laboratory (Dated February 2012). Available from: http://www.bv.com/docs/reports-studies/nrel-cost-report.pdf. [Last accessed on 2014 Nov].

Brattle Group. (2014), Estimating the Economically Optimal Reserve Margin in ERCOT (dated January 31, 2014). Available from: http://www.brattle.com/system/publications/pdfs/000/004/978/original/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf?1395159117. [Last accessed on 2014 Apr].

Corrado, C., Mattey, J. (1997), Capacity utilization. Journal of Economic Perspectives, 11(1), 151-167.

ECCO International. (2013), 2012 ERCOT Loss of Load Study (dated March 8, 2013). Available from: http://www.ercot.com/content/gridinfo/resource/2014/reservemargin/ERCOT_Loss_of_Load_Study_2013PartII.pdf. [Last accessed on 2014 Nov].

Electric Reliability Council of Texas (ERCOT). (2014a), Demand and energy (% by fuel type of energy by month): energy by fuel type percent for 2014 (dated October 7, 2014). Available from: http://www.ercot.com/content/news/presentations/2014/ERCOT2014D&E.xls. [Last accessed on 2014 Nov].

Electric Reliability Council of Texas (ERCOT). (2014b), Resource Adequacy Assessments: capacity, Demand and Reserves Report – May 2014: summer Capacities or Summer Summary. Available from: http://www.ercot.com/gridinfo/resource/index.html. [Last accessed on 2014 Nov].

Electric Reliability Council of Texas (ERCOT). (2014c), ERCOT Report on the Capacity, Demand, and Reserves in the ERCOT Region (dated February 2014). Available from: http://www.ercot.com/content/gridinfo/resource/2014/adequacy/cdr/CapacityDemandandReserveReport-February2014.pdf. [Last accessed on 2014 Nov].

Federal Reserve. (2014), Industrial Production and Capacity Utilization - G.17: Table 2 - Capacity Utilization: manufacturing, Mining, and Utilities (dated November 17, 2014). Available from: http://www.federalreserve.gov/releases/G17/Current/table2_sup.htm. [Last accessed on 2014 Nov].

Garner, C.A. (1994), Capacity utilization and U.S. inflation. Federal Reserve Bank of Kansas City. Economic Review, 4th Quarter p. 5-21. Available from: https://www.kansascityfed.org/Publicat/Econrev/EconRevArchive/1994/4Q94GARN.pdf. [Last accessed on 2014 Nov].

Krugman, P., Wells, R., Graddy, K. (2013), Essentials of Economics. 3rd ed. N.Y: Worth Publishers.

Mankiw, N.G. (2014), Essentials of Economics. 7th ed. Stamford, CT: Cengage Learning.

Nelson, R.A. (1989), On the measurement of capacity utilization. Journal of Industrial Economics, 37(3), 273-286.

Nikiforos, M. (2013), The (normal) rate of capacity utilization at the firm level. Metroeconomica, 64(3), 513-538.

Prentis, E.L. (1987), Operations management taxonomy. Journal of Operations Management, 7(1), 63-78.

Prentis, E.L. (2014a), Deregulation & privatization: Texas electric power market evidence. Review of Business and Finance Studies, 5(2), 117-126.

Prentis, E.L. (2014b), U.S. electrical system reliability: deregulated retail choice states' evidence and market modeling. International Journal of Energy Economics and Policy, 4(4), 588-598.

Prentis, E. L. (2015), Evidence on U.S. electricity prices: regulated utility vs. restructured states. International Journal of Energy Economics and Policy, 5(1), 253-262.

Ray, S.C., Mukherjee, K., Wu, Y. (2006), Direct and indirect measures of capacity utilization and economic growth: a nonparametric analysis of U.S. manufacturing. The Manchester School, 74(4), 526-548.

Sioshansif, R., Tignor, A. (2012), Do centrally committed electricity markets provide useful price signals? The Energy Journal, 33(4), 97-118.

Stevenson, W. J. (2014). Operations Management. 12th ed. N.Y: McGraw-Hill.

U.S. Energy Information Administration (EIA). (2012a), Electric Generator Dispatch Depends on System Demand and the Relative Cost of Operation (dated August 17, 2012). Available from: http://www.eia.gov/todayinenergy/detail.cfm?id=7590. [Last accessed on 2014 Nov].

U.S. Energy Information Administration (EIA). (2012b), Electric sales, revenue, and average price: average retail price for bundled and unbundled consumers by sector, Census Division, and State – Table T4—2012 Total Electric Industry- Average Retail Price (cents/kWh). Available from: http://www.eia.gov/electricity/sales_revenue_price/pdf/table4.pdf. [Last accessed on 2014 Nov].

U.S. Energy Information Administration (EIA). (2013a), Capital Cost for Electricity Plants: updated Capital Cost Estimates for Utility Scale Electricity Generating Plants: Table 1. Updated estimates of power plant capital and operating costs. Table 4. Regional cost adjustments for technologies modeled by NEMS by Electric Market Modul (E) (dated April 12, 2013). Available from: http://www.eia.gov/forecasts/capitalcost/. [Last accessed on 2014 Nov].

U.S. Energy Information Administration (EIA). (2013b), Factors affecting electricity prices. Available from: http://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices. [Last accessed on 2014 Nov].