STUDY RESULTS

ESTIMATES OF MARGINAL COSTS OF ELECTRICITY SUPPLY IN 2010

prepared for:
THE BARBADOS LIGHT & POWER COMPANY, LIMITED
by:

Robert J. Camfield
Bruce R. Chapman
David A. Armstrong
CHRISTENSEN ASSOCIATES ENERGY CONSULTING

June 23, 2008, with amendments

Introduction

This report presents estimates of the marginal cost of electricity services provided by The Barbados Light & Power Company, Limited ("BLPC" or "the Company") during 2010. The study assumes that natural gas has not yet become available to the island.[1] The analysis includes load- and nonload-related marginal costs. All costs are reported in nominal BBD dollars for the year 2010.

While there are several potential applications of marginal costs, it is envisioned that the study results will serve as the basis for:

1) the allocation of financial costs to consumer and tariff groups on a trial basis only (rather than as the basis for costing and pricing in a general rate case); and,
2) support for the development of retail tariffs, where the end result is price incentives for consumers to use electricity efficiently.

The report provides a brief review of the marginal costing methodology, presents the results of the analysis, and concludes with a summary including observations on the implications for time-differentiated retail rates for BLPC. Two appendices supplement the main report. Appendix A provides monthly marginal energy and reserves cost information to extend the annual and seasonal results reported in the main body of the report. Appendix B outlines the general methodology applied in the analysis.

---

[1] Barbados may potentially obtain natural gas supplies from an undersea pipeline across the Lesser Antilles island chain. The pipeline is currently under consideration. The realization of the pipeline would dramatically diversify Barbados's fuel supply, leading to significant changes in the fuel and generation mix of BLPC. Similarly, this natural gas scenario, through its impact on generation mix and fuels, would likely have significant impacts on marginal costs over future years.

Marginal Cost Methodology

Marginal cost is the change in total cost with respect to a change in the level of output, where output refers to the production and delivery of goods and services. Marginal costs are specific to industry and technology, and the goods and services that are produced. Electric utilities provide retail consumers with bundled electricity services that include:

- *generation services* in the form of energy and reserves;
- *transmission and distribution services* (*wires services*) which provide for the transport of power between locations where it is produced (generators) and locations where it is consumed (customer sites); and,
- *interconnection services* involving the physical connection of customers to distribution (and transmission) networks. For purposes of this study, interconnection services also refer to billing services, which involves the process by which the commercial relationship between retail consumers and the service provider is managed and handled.

Marginal costs are often described as either *short-* or *long-run*.[2] The most relevant definition for costing and pricing electricity services is short-run marginal cost ("SRMC"), as determined for either real-time or forward periods. As a practical matter, however, short-run marginal costs for wires and interconnection services are not readily observable. Thus, for these services, long-run marginal costs ("LRMC") are used as surrogates for forward-looking short-run marginal costs.

Generation Services

Marginal generation costs consist of *Energy* and *Reserves* components, where reserves ensure that electricity services are provided with the appropriate level of reliability and are thus associated with the term marginal reliability costs. *Marginal Energy Cost* refers to the incremental fuel and variable operating and maintenance costs associated with a change in load level. *Marginal Reliability Cost* can be defined from the perspective of either *Consumer Outage Costs* or *Capacity Costs*. Outage costs refers to the value foregone by consumers as a result of

---

[2] Short-run marginal cost is the change in short-run variable costs with respect to a change in load. Some costs remain unchanged in the short run, and are thus referred to as fixed costs. That is, the timeframe—*e.g.,* the day ahead—is too short for physical facilities currently in place (the stock of capital) to be altered or adjusted. Essentially, in the short run, the capital-related charges and fixed operations and maintenance costs ("FOM") associated with physical facilities do not vary as load varies.

Under LRMC, all costs including capital costs and FOM vary in response to a change in load level. This means that, in the long run, a change in the expected load level precipitates adjustments to physical facilities in order to obtain the desired (least total cost) resource configuration and mix. In the context of the real world, long-run adjustments—*i.e.*, the implementation of adjustments to obtain the least cost configuration—could take a very long time. Indeed, the process of implementing long-run adjustments to realize the optimal configuration is likely to be taking place *as the optimal configuration target is also evolving*. As a practical matter, then, the LRMC definition of marginal cost is most relevant as a conceptual view. In brief, LRMC is the change in total cost with respect to a change in load if all resources could be adjusted to the optimal configuration *overnight*.

The most useful definition of marginal cost is *ex post* and forward-looking short-run marginal costs, where forward-looking SRMCs embody expected long-run adjustments. Accordingly, the immediate discussion is confined to SRMC, although capacity cost proxies, which are LRMC adjustments, are used as SRMC surrogates for both generation capacity and power delivery ("transmission and distribution" or "T&D").

not having electricity service, while capacity costs refers to the annual charges related to installation of capacity. Marginal generation costs are, of course, load-related costs.

Marginal Energy Cost: Estimates of marginal energy costs are developed by simulating BLPC's dispatch process for 2010. The simulation is based on the Company's projections of peak demands, primary fuel prices, and installed generation for this forward year, and incorporates generator unit parameters including effective capacity, heat rates, variable operations and maintenance costs ("VOM"), maintenance time, availability, forced outage rates, and time to repair.

For 2010, the level of supply consists of BLPC's expected available generators for the year, including the installation of a new base load unit. Similarly, the level of electricity demand for 2010 is the Company's forecast of load and energy. The simulations are performed on hourly data, using the 2006 load profile as the basis for the projected hourly loads for 2010. The computer algorithm underlying the simulations of marginal cost utilizes Monte Carlo methods to determine the availability of individual units within each hour, based on the expected forced outage rates of the units. Estimates of the hourly marginal energy cost, as presented, are the average of multiple simulations, where each iteration is an 8,760 hourly sequence of energy costs.

As noted above, the starting point is BLPC's expected generation set for 2010. The analysis procedures begin with maintenance scheduling, where individual units are scheduled for maintenance within the year according to the principle of least cost impact. Once generator maintenance is scheduled, the algorithm then determines the availability of the units. Each iteration represents a different forced outage realization, leading to different sets of generators and reserve levels across hours. The set of available generators is then ordered according to running costs (fuel and VOM). For a simulation, the marginal energy cost in an hour of 2010 is the running cost of the highest cost unit dispatched in order to satisfy the load in the hour.

Marginal Reliability Cost: Generation capacity provides energy and reserve services. Reserves provide the necessary level of reliability. For this study, marginal reliability costs are based on both the capacity cost and consumer outage cost methods. Under the conditions of complete foresight and knowledge regarding the future need for capacity and the costs of resources, and where resource indivisibility is not present, optimal least cost planning yields marginal capacity costs that approximate marginal outage costs. This means that the cost of the last kW of planned and installed capacity approximates the expected value of outages costs incurred by consumers.[3] For several reasons, these conditions are only rarely satisfied, leading often to major differences

---

[3] The dispatch simulations demonstrate that the addition of the new unit in 2010 results in total benefits, including reduced outage costs and lower fuel costs, which together exceed the annual costs associated with capacity. This is a result of the exceptionally high fuel costs at the time of the study. As evidenced by NYMEX prices on contracts for 2010 delivery, the consensus view during mid-2008 was that high contemporary fuel costs would remain largely intact, showing only modest abatement through 2010. If true, major reductions in total fuel costs would result from the installation of additional base load generating units by the Company. Essentially, the unexpected and exceptionally high fuel costs, should they be sustained at the then-current levels, impose a generation mix imbalance condition on BLPC. However, the perspective reflected in the immediate study, in sharp contrast to the consensus view, is that fuel costs for 2010 will decline significantly from mid-2008 levels.

between marginal capacity and outage costs within an annual period. Hence, both approaches are undertaken in the current study.

Capacity Cost (Model I): As mentioned, marginal capacity cost is equal to the charges for an increment of capacity, stated as $/kW for an annual period.[4] These annual charges cover capital costs including depreciation, property taxes, and income taxes; and fixed operations and maintenance expenses, general plant, working capital, and A&G costs.[5] The methodology to determine the annual charges is discussed below. Marginal capacity costs also incorporate the impact of changes in peak loads on BLPC's installed reserve requirements (30%) and, as applied in the study, account for a share of the fuel cost savings.

Outage Cost (Model II): The *Outage Cost* approach is implemented directly within the simulation of marginal energy costs, as discussed above. Specifically, under the simulated condition where generation supply is less than demand, retail consumers experience outage costs. Because outages occur as rather lumpy and indivisible events, the estimate of consumer outage cost, defined at a level of about $6 BBD per kWh, is set equal to $15 BBD per outage event *for purposes of model simulation*.[6]

The outage cost model is based on the Company's expectations of demand and supply for 2010. Given the analysis assumptions, the outage frequency is estimated to be about 25 hours (LOLH). This is a static level of outage events.[7] By definition, however, marginal cost is equal to the change in cost—in this case, outage costs—with respect to a change in load. So, if hourly loads are increased (decreased) by 1MW, a truer estimate of marginal expected unserved energy can seemingly be obtained. However, outage frequency obtained from an incremental/decremental approach may be somewhat larger than that which results from static analysis. Accordingly, the static level of outages can be viewed as a first order approximation to the change in expected unserved energy.

Wires Services

The Company's wires services are provided by radial and, to a lesser extent, meshed network transmission and distribution facilities. Marginal costs of wires services include both load- and nonload-related dimensions. In essence, wires costs are jointly determined by peak loads (load-

---

[4] The choice of technology for the incremental generator accounts for a number of factors and constraints; multiple criteria must be satisfied. Potential fuel cost savings are a major consideration, and the incremental generator is often a base or intermediate unit, where its installation results in both fuel cost savings as well as improved reliability. Fuel cost savings can (should) more than offset the higher capital costs. Accordingly, to determine the costs of reliability (reserves) under this situation, the planned or observed capacity costs of new unit should be adjusted for the expected fuel cost savings offset. This is the case with the Company's generation plan for 2010, where the planned incremental unit is a base load unit.

[5] Arguably, marginal cost estimates should also cover materials and supplies, including fuel inventories.

[6] This outage cost level may be understated, depending on the depth (MWs) of load interruption events initiated by BLPC in order to maintain system reliability. Essentially, load interruptions are characterized by resource indivisibility, much like capacity.

[7] The depth of unserved load, referred to as unserved energy (EUE) is not taken into account.

related) and consumer locations and transport distances (nonload-related).[8] Often, transmission is distinguished from distribution by voltage level. However, BLPC classifies all wires services as distribution, which includes underground and overhead facilities.

This study assumes a long-run marginal cost approach which is applied in two ways, referred to as *Historical Analysis* and *Planning-Based* methods. The historical analysis estimates the historical relationship between the real capital stock (2006 $BBD)[9] of wires facilities and peak demands and customers served. This analysis approach uses statistical techniques to estimate the relationship, expressed as a linear equation.[10] Essentially, the estimated equation serves as the basis to determine the impact of changes (increases) in peak loads, and number of customers on the investment experience of the Company over time. The planning-based approach is based on BLPC's detailed expansion plans for the 2007 – 2010 timeframe. The Company's plans are developed in considerable detail, including 35 individual construction projects along with 16 categories of equipment that will be ultimately booked to the appropriate distribution and general plant categories of plant-in-service capital accounts.

The dual approach including historical analysis and planning-based methods provides a means to verify power delivery marginal cost estimates—essentially, a cross-check. Indeed, the historical analysis implies that BLPC's capital expenditures for wires services will be $30.4 million BBD in order to satisfy expected growth in the number of customers and peak demands over 2007 – 2010. The planning-based method yields a similar level of anticipated investment expenditure of $35.4 million BBD in order to satisfy growth, over the same timeframe. The historical analysis is particularly useful because it provides the means to estimate the load- and nonload-related costs associated with wires services. The historical analysis-based load-related marginal costs are then scaled to levels that approximate the expected costs for growth, as developed by BLPC for planning.

---

[8] All non load-related marginal costs are stated in terms of $/customer.

[9] The development of the real capital stock utilizes a geometric decay function to capture economic depletion—essentially, the loss in the value of services provided by the capital stock over time. This approach is consistent with the methods utilized by Christensen-Jorgenson, which are widely used to value capital.

[10] More specifically, the estimated time series equation is obtained through conventional OLS regression techniques. The equation contains four right-hand-side ("RHS") variables including peak demand, number of customers, time, and a binary variable representing the years 1994—1996. Together, these RHS factors explain 90.3% of the variation in the real capital stock, with an F value of 47.6. Because of the substantial degree of multicollinearity inherent in the RHS variables—which is common to models of this type—the statistical significance of the RHS variables range between comparatively small to modest. The number of observations is small, and the statistically estimated equation is fragile. As a result, the relationship between capital investment and RHS variables, as identified, is tenuous.

Alternative model specifications were explored. BLPC's real capital stock invested in power delivery facilities is declining steadily, after accounting for positive effects of the year-over-year rise in peak demand and number of customers served. Accordingly, the coefficients for *demand* and *customers* are adjusted, to account for the downward slope *with respect to* time. This out-of-sample adjustment is based on the inference that economies of scale are present in BLPC's process of producing power delivery services, with the impacts manifest as steadily declining marginal (and average) load- and customer-related marginal costs. While the marginal cost results comport well with recent history and the planning-based estimates of marginal cost for BLPC, such adjustment to regression coefficients is arguably *ad hoc* and without a firm analytical foundation.

The marginal costs of wires services are stated as $/kW (load-related) and $/customer (nonload-related) for an annual period. Similar to generation capacity, the annual charges for wires services cover the various types of capital-related charges, including carrying costs, depreciation, property and income taxes; and fixed operations and maintenance expenses, general plant, working capital, and A&G costs.

Interconnection Services

The incremental costs of interconnection services include load- and nonload-related (customer) costs associated with the connection of retail consumers to BLPC's distribution facilities. Interconnection services cover the capital, installation, and maintenance costs of electrical equipment, which are typically recorded within the capital accounts of power delivery. Interconnection services include voltage transformation, metering, and connection via service drops. As mentioned, this study incorporates billing and customer services within interconnection.

Incremental interconnection costs are based on observed costs incurred by the Company to provide interconnection service, involving several samples of experience. For residential interconnections, the sample includes the following:

- *Single Family Dwellings:* three samples of overhead service covering 10-57 lots each, and with corresponding costs of $14,000-$45,000; and three samples of underground service covering 18-63 lots each, with costs of $86,000-$449,000.
- *Multiple Family Dwellings:* one sample of overhead service covering four lots with cost of $13,000; and three samples of underground service covering 14-21 lots each, at costs of $82,000-$120,000.
- *Single Dwellings, Large:* three sample of underground service, where two of the samples are for individual properties, and the third covers nine lots. The corresponding costs are $16,000, $85,000, and $105,000, respectively.

The samples of commercial and industrial interconnection include the following:

- *Commercial (SVP Tariff):* three samples of overhead service with design capability of 10-25 kVA, with corresponding costs ranging from $9,000-$12,000; and five samples of underground service with design capability of 50-300 kVA, with costs ranging from $11,000-$33,000.
- *Industrial (LP Tariff):* two samples of underground service with design capability of 1500 kVA and 1350 kVA, with corresponding costs of $60,000 and $90,000, respectively.

The analysis proceeds by first determining the nonload-related investment cost associated with minimum service, estimated to be $129/customer, which is obtained from the samples of domestic customers. This customer interconnection cost is then imputed for the commercial and industrial samples. The analysis suggests that, as expected, overhead costs are less than that for underground facilities. Second, load-related interconnection costs decline as the load level rises, a result that can be attributed to the substantial economies of scale inherent in interconnection facilities.

The incremental billing and customer services costs are, by assumption, set at a level equal to the average cost of providing billing and customer services. The analysis for billing and customer services costs is based on the historical trend (log-based assessment of growth) in the Company's observed costs over the 1997—2006 timeframe. The estimated average billing cost per customer declined 1.57% annually over this period. The analysis presumes that this trend will continue, which translates into marginal (direct) costs of $75.89 BBD per customer in 2010, stated in nominal terms.[11]

As with marginal generation capacity and power delivery costs, the annual $/kW and $/customer charges cover capital carrying costs including depreciation, property taxes and income taxes; and fixed operations and maintenance expenses, general plant, working capital, and A&G costs.

Annual Charges: Capacity and Nonload-Related Costs

As detailed above, marginal capacity and nonload-related costs are stated as annual $/kW and $/customer charges, and involve several components, each of which can be expressed as a percentage of investment costs. The methodologies used for determining the components of capacity and nonload-related charges are as follows:

- *Capital Carrying Costs:* The approach taken in this study is based on the *Economic Carrying Charge* ("ECC") approach. The ECC is a mathematical expression, which is obtained through a conceptual simulation of the financial impact of a *change in the future path* of capacity and investment, such as generating capacity, in response to a change in expected resource demands in the future, representable as peak loads. An underlying assumption of the ECC methodology is successive replacement of equipment following the full depletion of capital. The ECC expression yields a series of annual ECC rates, stated as a percentage of investment, that cover the total financial charges on investment for capacity over the life of that capacity. While the ECC approach covers financial costs over the life of capital stated in discounted terms, the ECC rate for any one year is often sharply different (either higher or lower) from the annual financial cost rate, as determined on a basis of financial accounting. For this study, the capital carrying cost—*i.e.*, the ECC rate expressed as an annual percentage—is for the first year following investment.

  The ECC rate is determined by applying the derived form and incorporates the overall weighted average cost of capital, corporate income tax rate, expected net inflation, and capital depletion and life of capital. For this study, the ECC rates reflect a 5.25% cost rate for debt, 13.50% cost rate of equity, debt and equity participation of 35% and 65% respectively, and an income tax rate of 15%. These assumptions are consistent with the cost of capital and corporate tax rates for BLPC. The other assumptions and the resulting first-year ECC rates are shown in Table 1 below.

---

[11] It is essential to note that the marginal billing and customer costs can vary greatly according to type and size of customers. Accordingly, billing and customer costs should be differentiated in follow-up analysis, particularly for marginal cost-based cost allocation.

Table 1
Economic Carrying Charge Rates and Underlying Assumptions

Class of Capital	1st Year ECC Rate	Rate of Capital Depletion	Life of Capital	Net Annual Escalation Rate, Investment Cost
Generation	10.44%	3.46%	29	0.84%
Wires Services	11.34%	5.68%	18	1.47%
Interconnection	10.54%	5.41%	18	2.64%
General Plant	11.54%	6.11%	16	2.00%

- *Working Capital:* The allowance for cash working capital is set according to the 45-day rule, which translates into 12.5% of the fixed operations and maintenance expenditures, for each class of capital.[12]
- *Property Taxes:* The annual charges for property taxes are equal to 0.65% of the marginal investment costs, which is applied to each class of capital.
- *A&G Expenditures:* Administrative and General ("A&G") expenses are determined according to the trend in the historical relationship between A&G and non-fuel O&M expenses for BLPC during 1997—2006. A&G expenses are rising very fast (5.50% per year) in relative terms over this timeframe. However, A&G expenses declined significantly during 2006. Thus, the A&G rate for 2010 used in the study is the average A&G rate for the 1997—2006 period of 29.48%.
- *Fixed Operations and Maintenance Expenses:* Fixed operations and maintenance expenses ("FOM") expenses are determined from the trend in the historical relationship between FOM and the real capital stock over the 1997—2006 timeframe, for wires and interconnection services. The trend in this relationship is projected to continue through 2010 and, stated as a percentage of capital, is equal to 11.54% and 1.23% respectively. For generation capacity, the FOM rate of 3.22% is derived from the projected FOM costs provided by the Company for the planned LSD3 unit.
- *General Plant:* The annual charge rate—and thus the annual charges—for general plant are determined from the trend in the historical relationship between the real capital stock for general plant and that for generation and power delivery, for 1997—2006. The historical estimated trend reveals that the real stock of general plant is rising at 1.79% faster than other classes of capital. However, general plant declines in relative terms through 2003, and rises thereafter. Consequently, for 2010, the study utilizes the average level of general plant per unit of capital stock in generation and wires for '97-'06 in lieu of an extrapolated trend, to determine the general plant capital rate (adder) of 8.36%. In other words, general plant is equal to 8.36% per unit of real capital stock underlying each of the unbundled services including generation, power delivery, and interconnection. This means, for example, that a marginal investment of $100/kW translates into an

---

[12] The working capital amount, as used within this study, would be somewhat higher if materials and supplies were incorporated into the marginal cost calculations.

effective investment of $108.36/kW. For interconnection services, the value is set at 10%.

Table 2 presents the annual charge rates used to determine load- and customer-related (*i.e.*, nonload-related) marginal costs.[13] Generation and power delivery investment costs appear in the leftmost column.

Table 2
Investment Costs and Annual Charge Rates for Marginal Costs

	Investment Cost	Carrying Charge Rate (%)	Real Fixed O&M Rate (% K)	Real A&G Rate (% FOM)	Property Taxes (% K)	Working Capital (%)	General Plant (% K)
Load-Related							
Generation	$1,958.00	10.44%	3.22%	29.48%	0.65%	12.50%	8.36%
Wires Services	$354.74	11.34%	11.54%	29.48%	0.65%	12.50%	8.36%
Interconnection		10.54%	1.23%	29.48%	0.65%	12.50%	10.00%
Customer-Related							
Wires Services	$2,379.77	11.34%	11.54%	29.48%	0.65%	12.50%	8.36%
Interconnection		10.54%	1.23%	29.48%	0.65%	12.50%	10.00%

Marginal Line Losses

Marginal line losses are derived from the recent line loss study conducted by BLPC. Loss studies yield estimates of average losses, and reflect average load levels. The results of the loss study appear in Table 3 below. By definition, marginal losses are two times the level of observed average load-related losses at all load levels. For purposes of this study, marginal line losses are developed for primary and secondary service levels[14] and reflect load-related losses only[15, 16]

---

[13] The annual charge rates for FOM, general plant, and A&G are estimated from observed historical cost experience, stated annually. The study approach inherently captures, as a matter of method, average FOM, A&G, general plant costs, not marginal costs of the resources employed in these activities. During previous eras, substantial departures between average and marginal costs were present in the cost structure of these activities, as utilities were transitioning to a much more intensive use of information technologies, particularly for the various activities that support the direct line functions including generation, transmission, and distribution. The result was much higher levels of productivity, under employment in support functions, and large departures between average and marginal costs within the functions themselves. These conditions, in general, are no longer present and, to the degree that the condition of underemployment of resources has been exhausted, average and marginal costs are more closely aligned. Nonetheless, the issue of whether average costs are an appropriate surrogate of marginal costs for FOM, general plant, and A&G remains an open question.

[14] The analysis of losses incorporated into the study utilizes the updated definitions of levels provided by BLPC.

[15] That is, average and marginal no-load losses are equivalent.

[16] Arguably, it is appropriate to include the *marginal effects* of no-load losses within marginal customer costs, as the presence of electricity consumers on BLPC's network gives rise to the loss of energy that is unrelated to loads.

Table 3
Average Line Losses, From BLPC Loss Study

Load Level	No-Load Losses % Net	Load Losses % Net	Total Losses % Net
Transmission	0.08	1.71	1.79
Substation Transformers	0.39	0.11	0.50
Primary Losses	0.08	2.63	2.71
Distribution Transformers	0.18	0.58	0.76
Secondary Losses	0.01	1.53	1.54
Total	**0.74**	**6.56**	**7.30**

Marginal line loss percentages appear in Table 4, below. Cumulative marginal losses shown in Table 4 are the multiplicative loss factors to be applied to marginal generation and load-related wires costs, to determine the marginal costs of BLPC by service level. Incremental losses reflect the load-related loss percentages.[17]

Table 4
Marginal Line Loss Percentages

Load Level	Average	Peak Load	Off Peak
Transmission	3.42%	3.90%	2.98%
Substation Transformers	0.22%	0.25%	0.19%
Primary Losses	5.26%	6.00%	4.59%
Distribution Transformers	1.16%	1.32%	1.01%
Secondary Losses	3.06%	3.49%	2.67%
		Cumulative Marginal Losses	
Primary	8.90%	10.15%	7.77%
Secondary	13.12%	14.97%	11.45%
		Incremental Line Losses	
Primary	8.17%	9.22%	7.21%
Secondary	3.73%	4.19%	3.30%

---

[17] The marginal loss factor used to differentiate generation costs by service levels is equal to 1/(1-incremental line loss %).

As shown, the marginal loss factors are developed for primary and secondary service levels, for peak and off-peak load levels which are 134.3 MW and 102.7 MW, respectively, for 2006.[18]

Load-Related Marginal Costs

Table 5 below presents capacity costs of load-related services, stated on a $/kW-year basis, for BLPC. The capacity cost estimates include generation and wires services, and eight categories of interconnection services covering various connection situations for the three main consumer groups (residential, commercial, and industrial) served by the Company.

For each type of capacity, the table presents the marginal investment costs and each of the carrying charge components. The rightmost columns display the total annual charges in Barbados and U.S. dollars, along with the all-in annual capital charge rates (CCR) shown as a percentage of investment.[19, 20]

Table 5
Estimates of Load-Related Marginal Capacity Costs of BLPC, 2010

	Investment Cost	Carrying Charges	Fixed O&M	A&G	Property Taxes	Working Capital	General Plant	Annual CCR (% of I)	Total Annual Charges ($ BB)	Total Annual Charges ($ US)
Generation*	$2,654.12	$277.09	$92.87	$27.38	$18.76	$1.57	$20.85			
Full Costs								16.52%	$438.51	$219.26
Net of F&VOM Savings								7.10%	$188.51	$94.26
Wires Services	$376.06	$42.65	$45.28	$13.35	$2.55	$0.83	$3.70	28.81%	$108.35	$54.18
Interconnection										
Single Residential Small, Underground	$49.46	$5.21	$0.61	$0.18	$0.32	$0.01	$0.56	13.92%	$6.88	$3.44
Single Residential Large, Underground	$31.68	$3.34	$0.39	$0.11	$0.21	$0.01	$0.36	13.92%	$4.41	$2.21
Multi-Residential, Overhead	$19.19	$2.02	$0.24	$0.07	$0.12	$0.00	$0.22	13.92%	$2.67	$1.34
Multii-Residential, Underground	$15.24	$1.61	$0.19	$0.06	$0.10	$0.00	$0.17	13.92%	$2.12	$1.06
Small Commercial, Overhead	$54.70	$5.77	$0.67	$0.20	$0.35	$0.01	$0.62	13.92%	$7.61	$3.81
Small Commercial, Underground	$21.64	$2.28	$0.26	$0.08	$0.14	$0.00	$0.24	13.92%	$3.01	$1.51
Large Commercial	$17.74	$1.87	$0.22	$0.06	$0.11	$0.00	$0.20	13.92%	$2.47	$1.23
Industrial	$10.70	$1.13	$0.13	$0.04	$0.07	$0.00	$0.12	13.92%	$1.49	$0.74

* Includes Investment Coverage for Generation Reserves

The estimates of load-related interconnection costs reveal appropriate cost ordering. That is, the marginal costs for overhead services are less than those for underground service; and it costs less on the margin to serve multi-residential facilities than to serve single dwellings. Generally speaking, investment costs for capacity—and for nonload-related or customer costs also—reflect

---

[18] The average system load level in 2006 was 117.7MW.

[19] The carrying charge rates are determined by the life of capital and other input factors. The current study does not differentiate capital life across the various market segments served. However, if capital life of the interconnection equipment varies from one market segment to another, the true carrying charge rates would be differentiated accordingly.

[20] Generation capacity cost is based on the expected cost of the planned base load unit for 2010, and is shown with fuel and VOM savings ($188.51 BBD per kW-year) and without such savings ($438.51 BBD per kW-year). For purposes of determining marginal costs, the fuel and VOM cost savings are set equal to $250 BBD per kW-year. However, the analyses suggest that the true fuel cost savings are much higher, in view of the unprecedented high costs for primary fuels currently. For reference, the marginal capacity costs of the least cost candidate technology, simple cycle gas turbine, are $216.25 BBD per kW-year.

the comparatively high cost levels for all types of power system equipment in mid-2008, although costs have receded recently from these highs due to the world-wide recession .

Marginal load-related capacity costs, stated annually, are distributed to hourly loads. For generation, marginal capacity costs are incorporated into Model I hourly marginal costs only, as they carry a cost-based imputation of the cost of reserves. Marginal wires capacity costs are incorporated within Models' I and II hourly costs.[21]

As mentioned, load-related marginal costs include energy costs and capacity costs for generation (Model I) or consumer outage costs (Model II), and capacity costs for wires services.[22] For Model I, the annual charges for capacity presented in Table 3 are distributed to peak loads by a "maximum" function. That is, the closer the load of a given hour is to the level of the annual peak load, the greater the likelihood that reserves (extra capacity) will be needed in that hour in order to preserve reliability. Because peak loads determine the physical capacity needs of the Company's power system, including generation and wires services—and also interconnection facilities—capacity costs are distributed to hours where loads approach system peaks .[23]

In contrast, the outage costs incorporated into Model II reflect each individual hour's level of reserves. As mentioned above, outage costs occur where generation capacity (supply), as simulated, is insufficient to satisfy loads. Under this approach, the marginal cost of reliability may occur during months where consumption may not be near the peak but reserves are nevertheless occasionally low, or even negative—*i.e.,* the condition where supply falls short of demand.

Table 6 summarizes the estimates of BLPC's load-related marginal costs for generation and wires services, including both marginal energy and capacity or outage costs, averaged across scenarios and across days within months with similar overall marginal costs. Monthly detail appears in Appendix A. CA Energy Consulting used a statistical model to identify peak periods based on each model. Not surprisingly, given the differences in approaches to cost allocation between Model I (capacity cost) and Model II (outage cost), the statistical model identifies different peak periods. The peak period in Model I is found to be weekdays beginning in the hour ending 11:00 am and lasting through the hour ending 4:00 pm (hours 11-16, inclusive).

---

[21] The annual load-related costs of interconnection services are distributed to hourly loads of customer and tariff groups, rather than to system loads.

[22] Load-related marginal costs in total include load-related interconnection service costs. However, they cannot be allocated in the same manner as generation capacity and power delivery costs. This is because the time pattern of peak loads of interconnection facilities often deviate substantially from system loads, which as discussed serve as the basis for allocation of system-level capacity costs (generation and power delivery).

[23] The structure of the max function incorporates parameters that determine how broadly (or narrowly) capacity costs are distributed to loads/hours. For generation and wires services, capacity costs should be distributed relatively narrowly under conditions of fairly low system load factors. Conversely, comparatively high load factor power systems such as that of BLPC should generally have capacity costs distributed more broadly. Because there is often more diversity of peak loads among distribution systems, capacity costs for wires services should be distributed somewhat more broadly among loads, than for generation. Capacity costs for interconnection services should be distributed more broadly still, as there is substantial variation when peak loads occur among individual customers. Load diversity is also present for groups of customers on individual interconnection facilities, such as the facilities that provide connection service to multiple dwelling residences or to small businesses within, say, a retail outlet.

Model II's costing approach yields a weekday peak period of hours 10 to 21 inclusive. That is, the peak period that minimizes within-period marginal cost differences and maximizes between-period differences includes the evening hours in addition to the hours identified by Model I.

Average marginal costs are higher in the customer outage cost simulations (Model II) than in the capacity cost simulations (Model I). This difference is largely a result of the higher level of base load capacity in Model I than in Model II. In Model I, the additional capacity reduces both marginal energy costs and outage costs.[24] The annual averages are $0.381/kWh BBD for Model I and $0.477 BBD for Model II. That is, average marginal costs are about 25 percent higher in the outage cost simulations than in the capacity cost approach.

Marginal outage costs (about $335 BBD annually) are, for analysis purposes, not far from marginal capacity costs (about $188 BBD annually). This result is directly attributable to fuel cost savings, which are set equal to $250 per kW-year, as mentioned earlier. The difference in the level of average marginal costs between Model I and Model II simulations is also attributable to capital indivisibility. That is, capacity is added in increments of 30 MW, which means that the additional capability of 30 MW underlying the Model I results drives down marginal energy and outage costs significantly. It is our view that BLPC can expect to have near optimal reserve levels in 2010. This means that, if the Company could add, say, a mere 1-5 MW of reserves, Model I and Model II results would be nearly identical.[25] However, such result is not possible because of resource indivisibility.

---

[24] The average number of annual outage events across simulations for Model II analysis is 20, whereas the additional capacity within the Model I analysis reduces outage events to about 2, annually.

[25] Nonetheless, this scenario could be easily simulated.

Table 6
Summary of Forecasted Average Hourly Marginal Costs for BLPC, 2010
$/kWh BBD

	Model I: Capacity Costs				Model II: Outage Costs			
Day Type	Peak Hours (11-16)	Off-Peak Hours (1-10, 17-24)	All Hours	Non-Peak*	Peak Hours (10-21)	Off-Peak Hours (1-9, 22-24)	All Hours	Non-Peak
weekday								
Jan-Apr, Dec	0.494	0.360	0.394		0.636	0.381	0.509	
May-Jul, Nov	0.689	0.314	0.408		0.648	0.349	0.499	
Aug-Oct	0.886	0.324	0.464		0.739	0.360	0.549	
excl Aug-Oct	0.581	0.340	0.400		0.641	0.367	0.504	
Annual	0.657	0.336	0.416		0.666	0.365	0.515	
weekend								
Jan-Apr, Dec	0.336	0.314	0.320		0.437	0.362	0.399	
May-Jul, Nov	0.289	0.270	0.274		0.402	0.330	0.366	
Aug-Oct	0.301	0.274	0.281		0.408	0.334	0.371	
excl Aug-Oct	0.315	0.294	0.300		0.421	0.348	0.384	
Annual	0.311	0.289	0.295		0.418	0.344	0.381	
average								
Jan-Apr, Dec	0.449	0.347	0.372		0.579	0.376	0.477	
May-Jul, Nov	0.574	0.301	0.370	0.251	0.578	0.344	0.461	0.303
Aug-Oct	0.719	0.310	0.412	0.258	0.644	0.353	0.498	0.310
excl Aug-Oct	0.505	0.327	0.371		0.578	0.362	0.470	
Annual	0.558	0.322	0.381		0.595	0.359	0.477	

* Non-peak hours are all hours not included in the weekday peak period, *i.e.* all weekend & holiday hours plus off-peak hours of each weekday. Values are estimated indirectly based on approximate shares of hours in the period.

Marginal Cost Ratios

		Model I	Model II
Time of Day			
Aug-Oct	on-pk/off-pk, weekday	2.733	2.050
	on-pk/non-pk, all days	**3.433**	**2.381**
May-Jul, Nov	on-pk/off-pk, weekday	2.193	1.857
	on-pk/non-pk, all days	2.744	2.139
Seasonal			
	Aug.-Oct. vs. May-Jul., Nov.	1.115	1.082
	Aug.-Oct. vs. all other	**1.110**	**1.061**

The top panel of the table reveals that, in the case of the capacity cost approach (Model I), marginal costs peak in the months of August through October and that the months May to July and November are discernibly different from both the peak months and from the remaining months of the year, at least. Weekdays contain virtually all of the price variation, as weekends are fairly uniform year-round. The differences displayed on weekdays are clear and significant in the case of Model I (capacity costs) and less so in the case of Model II (outage costs). Additionally, average marginal cost is higher in Model I than in Model II in the peak months and lower in the off-peak months. This pattern reflects the way that capacity cost is distributed across hours close to the annual peak in Model I relative to the distribution of outage costs across hours of low reserves in Model II.

The higher variability of marginal costs in the capacity cost model appears most strongly in the peak hours of the three peak months. The August to October weekday peak averages of Models 1 and 2 are $0.886 and $0.739, respectively. The capacity cost approach predicts peak period values 20 percent above those of the outage cost approach.

The bottom panel of the table provides some illustrative ratios of marginal cost in different time periods. These ratios are useful in evaluating the benefits to BLPC of introducing time differentiation into its retail rates. The time is fast approaching when time-based metering will be more available and could be economical for large customers and a sizable number of secondary voltage customers as well. For customers with such metering, it is feasible to introduce either mandatory or voluntary time-of-use tariffs. Whether TOU pricing is desirable or not depends in part on the price responsiveness of customers and the time variation of marginal cost. Based on experience elsewhere, price ratios of roughly 3 to 1 or more tend to call forth sufficient response to justify consideration of TOU service. This ratio serves as a useful benchmark.

In order to apply this informal benchmark, we provide a column of marginal costs for "non-peak" hours, those hours in off-peak weekday and all weekend hours. As the bottom panel shows, Model I's results indicate that TOU service might be beneficial, at least for the three peak months of August through October. In this case, the on-peak to non-peak marginal cost ratio is 3.433 to 1, well above the threshold. However, Model II's marginal cost ratio is just 2.381 to 1, somewhat below the threshold, so there is no clear indication from this elementary test.

We provide seasonal marginal cost ratios as well in the bottom panel. Model I (generation capacity costs) indicates a modest degree of seasonality in the all-hours average marginal costs while Model II (consumer outage costs) finds virtually none. These data suggest that there may not be much value in seasonal price differentiation in BLPC's tariffs, unless significant differences in consumption profile exist between seasons for a particular customer class.

The pattern over the course of the day during a peak month reveals the role of the various components of marginal cost when they are high. Figure 1 presents average weekday marginal costs for September, 2010 in the capacity cost case (Model I). Marginal costs, averaged across the weekdays in the month are in the range of $0.20—0.30 in off-peak hours but climb above $1.00 during the peak period, reaching a high of about $1.10/kWh. Individual hourly marginal costs that contribute to this peak can go higher still. During high-cost hours the key factor is reliability cost, which captures the share of capacity cost assigned to these hours due to their relatively high probability of outages. Similarly, these are the hours in which transmission and distribution marginal costs are significant, although their average maxima are less than $0.20/kWh. In contrast, marginal energy cost in peak hours is typically in the $0.35 to $0.45/kWh range. Finally, in off-peak hours, the only costs of significance are marginal energy costs associated with generation.

Figure 1

September 2010 Weekday Average Marginal Cost, Model I

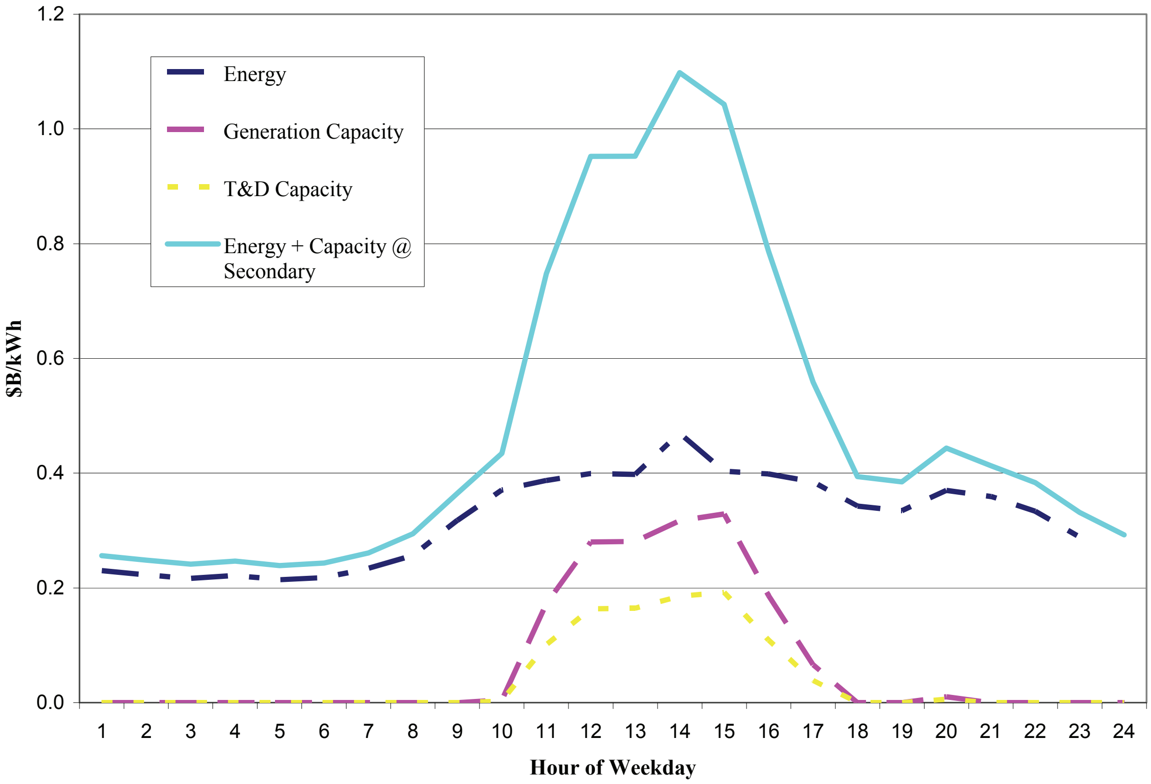


Figure 2 presents the average of the total marginal costs for each month under the assumptions of Model I, while Figure 3 provides the same information for Model II. In Figure 2, the three peak months of August to October appear to be clearly different from other months. Their wide solid lines are well above the other lines. The intermediate months (May-July and November), depicted in dotted lines of medium width, are discernibly below those of the peak months but also well above the thin solid lines of the remaining five months of the year (December to April).

Figure 2

Weekday Hourly Average Marginal Costs, Model I

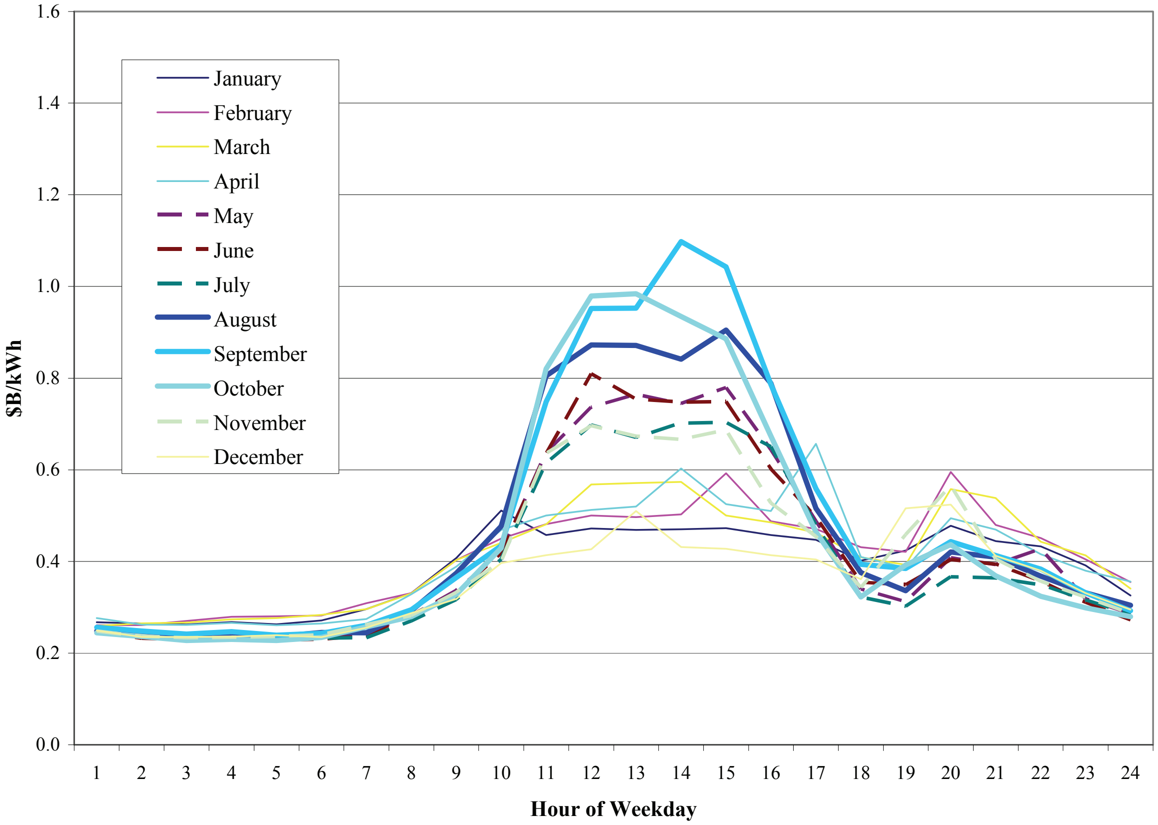
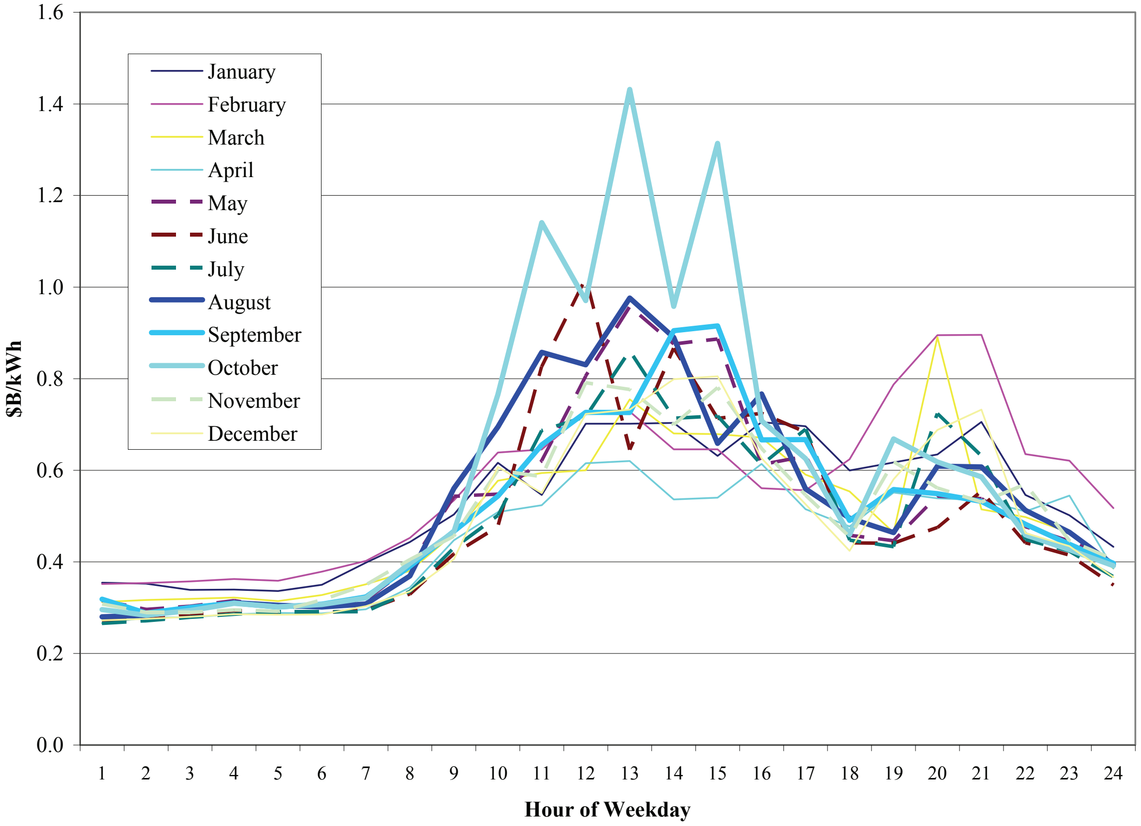


Figure 3, depicting the outage cost simulations of Model II, provides a decidedly different view of marginal cost from that of the capacity cost case of Figure 2. The peak period is less well-defined in the evening, with some winter months revealing an evening peak mildly above daytime levels. More importantly, there is less seasonal variation than in Model I. The August to October period is not significantly costlier than the intermediate months. The remaining months, again defined by the thin solid lines are only slightly less costly.

Figure 3

Weekday Average Hourly Marginal Costs, Model II



Observations on the Sensitivity of Results

As with any forecast, the results above depend upon the assumptions made. Several issues deserve comment. First, the simulations present BLPC's situation in 2010, which is anticipated to be a representative year for the period covered in and following the upcoming regulatory proceeding. This representation includes an extra generator not due to arrive until 2011. Our early simulations of 2010 produced levels of reserves that appeared to be lower than average for the five-year forecast period of BLPC's financial projections, and that represents the upper end of the period when new rates might reasonably be expected to apply. We advanced the new generator's arrival to counteract this situation and, at least plausibly, make 2010 to appear more representative of the longer period. This means that there is some chance of measurably higher marginal costs for at least some period in the not too distant future.

Second, the results are clearly sensitive to the method chosen to allocate reliability (capacity or outage) cost to the hours in the year. The methodologies used in the study distribute marginal reliability cost heavily in hours characterized by high outage likelihood but in different ways, resulting in different perspectives on the time pattern of load-related marginal cost. Each approach has its merits and the results reported herein generally conform to the experience of system planners and regional wholesale electricity markets in North America.

The differences in the results suggest that the evidence for introducing time differentiation in retail rates is not entirely convincing. While we understand the need to satisfy peak load, we lean somewhat in the direction of the outage cost model's perspective. This suggests that, for the near term, the study provides a basis for proceeding cautiously with regard to introducing time differentiation into retail rates.

The analyses presented herein suggest that BLPC should, at an appropriate time, pursue time differentiated pricing. There may be good cost-related reasons to price small customers seasonally and to offer at least a time-of-use option to larger customers. Such actions would permit BLPC to improve the relationship between costs and prices and to signal periods of relatively high cost to larger customers who may be able to shift consumption. The marginal costs and marginal cost ratios developed in this study—chiefly those of Model II—could then be used to inform pricing decisions.

For the medium term, BLPC may wish to improve further its marginal cost estimates. Several analysis paths are possible: 1) incorporation of variable outage scale (MW) within the analysis (Model II); 2) distribution of capacity costs to loads according to the hourly reserve position (instead of proximity to peak (Model I); 3) selecting alternative parameters of the algorithm used to distribute annual costs to loads and hours, yielding either a wider or narrower distribution of capacity costs (Model I); and 4) estimation of marginal generation costs for other years.

Nonload-Related Marginal Costs

Table 7, below, presents nonload-related marginal costs, stated as $/customer. As in Table 3, the estimated interconnection costs are differentiated by customer class and type, and include investment costs and the six components of the annual carrying charges. The annual charges are summed to the all-in annual charges, stated in Barbados and U.S. dollars, and as a percent of investment.[26] Because interconnection costs to serve large power customers are defined as exclusively load-related, nonload-related costs are reported as zero for these customers.

---

[26] Nonload-related marginal costs reveal, for the various types of consumers, the non capacity-related costs imposed on the system, and are vital to marginal cost-based cost of service and rate design studies. At a glance, the charges implied by the nonload-related marginal cost estimates are indicative. For example, the interconnection charges alone are larger than the $36 per year of customer charges for domestic customers. Analysis for larger customers will emerge from the marginal cost-based cost-of-service results.

Table 7
Estimates of Nonload-Related Marginal Costs, 2010[27]

	Investment Cost	Carrying Charges	Fixed O&M	A&G	Property Taxes	Working Capital	General Plant	Annual CCR	Total Annual Charges	
								(% of I)	($ BB)	($ US)
Wires Services	$2,522.82	$286.09	$303.93	$89.59	$16.40	$5.58	$24.84	28.79%	$726.43	$363.22
Interconnection										
Minimum Connection**	$129.09	$13.61	$1.58	$0.47	$0.84	$0.03	$1.45	13.92%	$17.97	$8.99
Single Residential Small, Underground	$2,067.30	$217.89	$25.31	$7.46	$13.44	$0.43	$23.25	13.92%	$287.79	$143.89
Single Residential Large, Underground	$10,518.08	$1,108.61	$128.79	$37.96	$68.37	$2.20	$118.30	13.92%	$1,464.22	$732.11
Multi-Residential, Overhead	$527.66	$55.62	$6.46	$1.90	$3.43	$0.11	$5.93	13.92%	$73.46	$36.73
Multi-Residential, Underground	$1,685.76	$177.68	$20.64	$6.08	$10.96	$0.35	$18.96	13.92%	$234.67	$117.34
Small Commercial, Overhead	$5,600.42	$590.28	$68.57	$20.21	$36.40	$1.17	$62.99	13.92%	$779.64	$389.82
Small Commercial, Underground	$8,387.90	$884.08	$102.71	$30.28	$54.52	$1.75	$94.34	13.92%	$1,167.68	$583.84
Large Commercial	$19,198.03	$2,023.47	$235.07	$69.29	$124.79	$4.01	$215.93	13.92%	$2,672.56	$1,336.28
Industrial***	$57,010.75	$6,008.93	$698.07	$205.78	$370.57	$11.91	$641.22	13.92%	$7,936.48	$3,968.24
Average Annual Cost of Billing*****			$75.89	$22.37		$1.29	$9.83		$109.37	$54.69

*** Derived from Dedicated Primary Costs
***** Attributed gen'l plant not observed

The inherent scale economies of interconnection are manifested in the pattern of declining marginal costs per kW of capability, as the design capability of interconnection facilities rise. Interconnection costs are highly specific to market context and locale, and also reflect the equipment choices, design patterns, and approach to the installation of facilities of individual utilities.[28]

Summary

BLPC's load-related marginal costs reveal hourly patterns and levels that reflect the variations in generation mix and reserve conditions across seasons and over the course of the day. However, the pattern, if not the level, depends on the method used to estimate economic and marginal costs. The capacity cost approach (Model I) presents a perspective of measurable variation across seasons and over the course of weekdays during the peak months of August to October. In contrast, the outage cost approach (Model II) offers a view of costs that vary somewhat less in both dimensions—season and time of day.

The study also provides estimates of BLPC's nonload-related marginal costs for 2010. These estimates highlight the significant costs that apply to customers on a nonvolumetric basis. At first glance they appear to be large relative to current fixed charges. This would be wholly consistent with traditional utility pricing, which frequently collects a portion of fixed costs through volumetric charges.

The marginal cost estimates obtained through this study, when paired with billing data and hourly interval data of the various customer classes, will provide BLPC with an alternative

---

[27] Non load-related marginal costs are reflected as $/Customer.

[28] As a general rule, for urban areas interconnection costs increase as customer and population density rises. Accordingly, we can expect that interconnection costs for the Island of Manhattan are likely to be higher than the costs for small metropolitan areas like Davenport, Iowa.

perspective on cost allocation to that of the typical physical quantities-based allocation of financial costs.[29]

The average marginal costs seen above provide mixed indications in terms of retail pricing and rate design. Regardless of costing perspective, there appears to be only modest seasonal variation in marginal cost, which follows from the pattern of system loads. We anticipate that combining marginal cost with load profiles will not affect this conclusion in the large, as most customers do not have a strong seasonal pattern. One exception might be the emerging subclass of residential customers who as visitors consume on a highly seasonal basis and at a high level. This fact alone may justify seasonal pricing of Domestic customers to ensure effective cost allocation.

Regarding inferences about time-of-use pricing, only the peak season appears to have significant on-peak to off-peak (or on-peak to "non-peak" hours *i.e.* including weekend hours), and this conclusion can be derived with some confidence from Model I only. However, it may be that time differentiation for this season—or for the shoulder period as well—among large customers will help to control peak demand growth without significantly increasing metering or billing costs. Conclusions here await further review with marginal costs combined with load profiles.

With this study BLPC has commissioned a first analysis of marginal cost in its system. This analysis may deepen understanding of cost causation and contribute to retail pricing decisions in BLPC's upcoming regulatory proceeding. We can suggest a number of steps that the Company can consider for the future to build upon this study. First, the immediate next step is to combine the load profile and marginal cost data to influence pricing decisions and to develop a partial marginal cost-based cost-of-service analysis that uses embedded cost to allocate overall costs to classes and marginal costs to influence the fractions recovered through fixed, capacity and energy charges.

Second, at its discretion the Company can improve its marginal costing capabilities further at relatively low cost. The range of scenarios considered here was limited. Additional investigation of demand fluctuations and the parameters that define the duration of unit outages are useful areas of exploration.

Third, the Company can use marginal cost-based cost allocation methods to set medium-term targets for implementation within future rate setting proceedings. The upcoming case will likely achieve some but may not achieve all strategic pricing goals. Since one reasonable goal is rate stability, large changes in price levels or in relative prices may require phased transition. Thus, marginal costs will serve as a planning tool to clarify future ratemaking and pricing goals.

---

[29] Because the causal linkage between levels of services provided and costs is only observable on the margin, marginal cost-based allocation is generally viewed as the better approach for allocation of financial costs to consumer groups and tariff classes. In addition, other potentially viable cost allocation methods are available including game-theoretic, separable costs-remaining benefits, economic rents, capacity and fuel cost savings (for generation), Ramsey Pricing, and *Aumann-Shapley Rule* approaches. (Robert J. Aumann recently received the Nobel Price in Economics)

Appendix A: The Monthly Pattern of Marginal Costs

The two-page table below provides monthly marginal cost information for each model, revealing the role of each component in costs. Each month has weekday and weekend results for marginal energy cost, marginal generation capacity cost, marginal transmission and distribution capacity cost and marginal total cost that includes a loss adjustment required to represent marginal cost at secondary voltage. Marginal costs are represented in $/kWh BBD.

The monthly data illustrate differences between the scenarios in terms of the components. Model I features generation capacity costs in several months and time periods. In contrast, Model II has no generation capacity costs but is instead characterized by consumer outage costs in the event of load outages caused by insufficient generation capacity.

The monthly pattern makes clear why we selected August to October to be peak months. The weekday peak hour and all hours marginal costs are measurably higher in these months for Model I, less so for Model II.

The table also provides supplementary information to Figure 1 in the main text. Capacity costs are concentrated in peak hours and peak months.

AVERAGE MARGINAL COST - 2010

$/kWh BBD

TIMEFRAME		MARGINAL COST COMPONENTS	Model I: Capacity Costs			Model II: Outage Costs		
			Peak Hours (11-16)	Off-Peak Hours (1-10, 17-24)	All Hours	Peak Hours (10-21)	Off-Peak Hours (1-9, 22-24)	All Hours
January	Weekday	Energy Cost	0.406	0.317	0.339	0.473	0.362	0.417
		Generation Capacity	0.000	0.000	0.000	0.097	0.000	0.048
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.466	0.360	**0.387**	0.655	0.408	**0.532**
	Weekend Day	Energy	0.299	0.286	0.289	0.408	0.349	0.378
		Generation Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.333	0.319	**0.322**	0.455	0.389	**0.422**
February	WD	Energy	0.444	0.329	0.358	0.480	0.374	0.427
		Generation Capacity	0.000	0.000	0.000	0.125	0.019	0.072
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.510	0.374	**0.408**	0.696	0.444	**0.570**
	WE	Energy	0.303	0.284	0.289	0.408	0.350	0.379
		Generation Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.338	0.316	**0.322**	0.455	0.390	**0.422**
March	WD	Energy	0.461	0.325	0.359	0.445	0.329	0.387
		Generation Capacity	0.000	0.000	0.000	0.103	0.000	0.052
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.530	0.369	**0.410**	0.631	0.371	**0.501**
	WE	Energy	0.325	0.285	0.295	0.358	0.310	0.334
		Generation Capacity	0.000	0.000	0.000	0.016	0.016	0.016
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.362	0.318	**0.329**	0.416	0.362	**0.389**
April	WD	Energy	0.440	0.323	0.352	0.448	0.305	0.376
		Generation Capacity	0.013	0.000	0.003	0.025	0.006	0.016
		T&D Capacity	0.007	0.000	0.002	0.004	0.000	0.002
		Energy + Capacity @ Secondary	0.528	0.368	**0.408**	0.548	0.351	**0.450**
	WE	Energy	0.310	0.286	0.292	0.360	0.290	0.325
		Generation Capacity	0.000	0.000	0.000	0.013	0.000	0.006
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.346	0.319	**0.326**	0.415	0.323	**0.369**
May	WD	Energy	0.370	0.272	0.297	0.457	0.320	0.388
		Generation Capacity	0.166	0.003	0.044	0.071	0.005	0.038
		T&D Capacity	0.097	0.002	0.026	0.051	0.000	0.026
		Energy + Capacity @ Secondary	0.718	0.316	**0.416**	0.660	0.367	**0.514**
	WE	Energy	0.258	0.240	0.245	0.367	0.304	0.335
		Generation Capacity	0.000	0.000	0.000	0.016	0.016	0.016
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.288	0.268	**0.273**	0.426	0.356	**0.391**
June	WD	Energy	0.410	0.270	0.305	0.435	0.292	0.363
		Generation Capacity	0.139	0.003	0.037	0.097	0.000	0.048
		T&D Capacity	0.081	0.002	0.021	0.043	0.000	0.021
		Energy + Capacity @ Secondary	0.716	0.312	**0.413**	0.656	0.329	**0.492**
	WE	Energy	0.261	0.242	0.247	0.339	0.293	0.316
		Generation Capacity	0.000	0.000	0.000	0.016	0.000	0.008
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.290	0.270	**0.275**	0.395	0.326	**0.361**

AVERAGE MARGINAL COST - 2010

$/kWh BBD

TIMEFRAME		MARGINAL COST COMPONENTS	Model I: Capacity Costs			Model II: Outage Costs		
			Peak Hours (11-16)	Off-Peak Hours (1-10, 17-24)	All Hours	Peak Hours (10-21)	Off-Peak Hours (1-9, 22-24)	All Hours
July	WD	Energy	0.367	0.260	0.287	0.437	0.294	0.365
		Generation Capacity	0.142	0.003	0.038	0.083	0.000	0.042
		T&D Capacity	0.083	0.002	0.022	0.044	0.000	0.022
		Energy + Capacity @ Secondary	0.673	0.301	**0.394**	0.645	0.332	**0.488**
	WE	Energy	0.258	0.244	0.248	0.331	0.276	0.304
		Generation Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.287	0.272	**0.276**	0.369	0.308	**0.338**
August	WD	Energy	0.437	0.281	0.320	0.457	0.318	0.387
		Generation Capacity	0.196	0.004	0.052	0.098	0.005	0.052
		T&D Capacity	0.115	0.002	0.030	0.061	0.000	0.030
		Energy + Capacity @ Secondary	0.847	0.327	**0.457**	0.701	0.366	**0.533**
	WE	Energy	0.270	0.247	0.253	0.354	0.295	0.325
		Generation Capacity	0.000	0.000	0.000	0.016	0.016	0.016
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.301	0.275	**0.281**	0.412	0.346	**0.379**
September	WD	Energy	0.409	0.288	0.318	0.467	0.319	0.393
		Generation Capacity	0.261	0.004	0.069	0.036	0.000	0.018
		T&D Capacity	0.153	0.003	0.040	0.080	0.000	0.040
		Energy + Capacity @ Secondary	0.930	0.335	**0.484**	0.661	0.360	**0.511**
	WE	Energy	0.285	0.251	0.260	0.362	0.296	0.329
		Generation Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.318	0.280	**0.289**	0.404	0.330	**0.367**
October	WD	Energy	0.359	0.265	0.288	0.452	0.314	0.383
		Generation Capacity	0.265	0.005	0.070	0.216	0.000	0.108
		T&D Capacity	0.155	0.003	0.041	0.082	0.000	0.041
		Energy + Capacity @ Secondary	0.880	0.310	**0.452**	0.854	0.355	**0.604**
	WE	Energy	0.255	0.240	0.244	0.367	0.292	0.330
		Generation Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.284	0.268	**0.272**	0.410	0.325	**0.367**
November	WD	Energy	0.378	0.277	0.302	0.456	0.321	0.388
		Generation Capacity	0.121	0.007	0.036	0.057	0.006	0.031
		T&D Capacity	0.071	0.004	0.021	0.042	0.000	0.021
		Energy + Capacity @ Secondary	0.648	0.328	**0.408**	0.633	0.369	**0.501**
	WE	Energy	0.260	0.241	0.246	0.374	0.297	0.336
		Generation Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.290	0.269	**0.274**	0.417	0.331	**0.374**
December	WD	Energy	0.373	0.287	0.308	0.408	0.295	0.351
		Generation Capacity	0.005	0.001	0.002	0.155	0.000	0.077
		T&D Capacity	0.003	0.001	0.001	0.002	0.000	0.001
		Energy + Capacity @ Secondary	0.437	0.328	**0.356**	0.649	0.333	**0.491**
	WE	Energy	0.269	0.268	0.268	0.348	0.283	0.315
		Generation Capacity	0.000	0.000	0.000	0.050	0.025	0.038
		T&D Capacity	0.000	0.000	0.000	0.000	0.000	0.000
		Energy + Capacity @ Secondary	0.300	0.298	**0.299**	0.443	0.343	**0.393**

Appendix B: LOAD-RELATED MARGINAL COSTS OF GENERATION AND TRANSPORT SERVICES

Marginal Costs and the Nature of Power Systems

Marginal cost refers to the change in total costs associated with a change in the services provided, and serves as the basis to assess resource options over future timeframes. More precisely, *load-related* marginal cost is the change in cost associated with a change in load *from a specific load level*, at a specific location within the power network and under specific supply conditions. Because hourly loads vary over the course of the day in reasonably consistent patterns, it can be said that load-related marginal costs vary according to time and location.

Economic costs are specific to industry, products and services and technology. Marginal costs of power service reflect the technology of production, including generators, fuels, transmission lines, and distribution systems. Marginal costs also reflect the conditions underlying supply, such as the performance of generating units, transmission line outages, and fuel costs. While generation technology changes slowly over decades and, by definition, remains static in the short run, the near-term conditions of supply can vary substantially, even within one hour or less.

The physical nature of power systems makes the task of marginal costing difficult and challenging. Electricity cannot be readily stored, and thus real-time demand for electric service is virtually identical to supply within each instant of time. Non-storability also means that inventory and time-basis arbitrage opportunities do not exist. The confluence of these attributes causes short-run marginal costs ("SRMC") of electric service to exhibit substantial variation within short periods—*e.g.,* individual hours of a typical day. While SRMC of off-peak hours can be less than $20/MWh, SRMC during peak loads can reach well above $500/MWh.[30]

Marginal Cost Estimation

Short-run marginal costs can reflect costs during *ex post* and *ex ante* (forward-looking) timeframes. *Ex post* marginal costs are reflected, for example, in real-time locational prices, as estimated by a facilitating agent of wholesale markets such as regional transmission organizations (("RTOs"), and are used for purposes of real-time transaction settlements. On the other hand, *ex ante* marginal costs over forward periods are estimated,[31] or observed as exchange-traded forward contracts. Forward periods can cover extended future periods. Because marginal costs are highly sensitive to system conditions, simulations of forward looking marginal costs involves estimates of future generator performance, estimates of capacity levels, primary fuel costs, and also the value of environmental externalities (environmental damage costs) over the relevant future periods.

---

[30] Unconfirmed wholesale prices within the ECAR region of the Eastern Interconnected System of the United States apparently reached $3.42/kWh ($3420/MWh) during the summer of 1997.

[31] Where markets are complete with readily available derivatives, forward and exchange traded futures provide a basis to infer the market's expectation of spot prices of electricity—which are essentially the marginal cost of the market, over future timeframes.

While marginal costs are specific to time and location, where locational differences are determined by constraints in power delivery including both transmission and distribution, integrated resource planning may not require locational granularity in the determination of forward-looking marginal costs. Nonetheless, the degree of locational cost variation is an empirical issue, and can only be discerned through network cost studies. Locational differences in marginal costs and wholesale prices may be substantial during periods of high load and/or low generating system performance, or when congestion tends to separate markets and define zones. In addition, the relative levels of capacity "tightness" within individual distribution feeders are likely to vary considerably and it seems feasible that marginal distribution costs could be differentiated across distribution feeders.

The discussion below presents two plausible models of marginal costs. ***Model I*** incorporates estimates of marginal capacity costs for generation, transmission, and distribution, whereas ***Model II*** utilizes consumer outage costs as surrogates for capacity cost—essentially, the shadow price of capacity costs.

MODEL I: *Capacity Cost as Surrogate for Reliability Costs*[32]

Marginal cost **Model I** is as follows:

$$SRMC^D_h = ((MEC_h+MEN+MC^G_h)*(1/(1-ML^T_h))+MC^T_h)*(1/(1-ML^D))+MC^D_h$$

where,

$SRMC^D_h$ = marginal cost at distribution voltage D, hour h
MC^G_h = marginal capacity cost of generation, hour h
MEC_h = marginal energy cost (generation), hour h
MEN = marginal environmental damage costs
MC^T_h = marginal cost of transmission capacity, hour h
MC^D_h = marginal cost of distribution capacity, hour h
ML^T_h = marginal line losses at transmission voltages, hour h
ML^D_h = marginal line losses at distribution voltages, hour h

Each of the above cost components is described below.

Marginal Energy Cost ("MEC_h") is the marginal running cost associated with a small change in load, and can be determined by simulating the generation dispatch process, sometimes referred to as *production costing*. Marginal energy cost can also be estimated as the incremental running costs[33] of the marginal generating unit within the generator stack at the time of the load change[34],

---

[32] Fundamentally, generation capacity jointly provides energy and reserve services. Reserves provide reliability. Essentially, the share of capacity held back and made available in the case of load changes and contingency events.

[33] Variable operations and maintenance (O&M) costs should also be recognized in marginal energy costs.

[34] This alternative approach presumes that, through some undefined means, the marginal generating unit for forward timeframes or for load levels can be identified.

and can be calculated by multiplying the marginal heat rate by the sum of the spot market price of fuel and incremental transportation costs for delivery of fuel to the plant site at which the marginal generating unit resides. Also, model simulations of wholesale electricity markets can be used to determine forward energy prices. Where service providers are efficiently trading power within the region, including both sales and purchases, gains from trade are essentially exhausted, such that the internal marginal costs of generation of the service provider and regional market prices are equivalent.

The estimation procedures should be geared to the application(s) of interest. For assessment of resource options for possible inclusion in integrated resource plans, simulations of hourly marginal energy costs are needed for several future years that account for expected new generators, which are determined with optimization methods. Constrained economic dispatch is simulated, the result of which is hourly running costs, which is usually reporting as total and average costs over defined timeframes. Operating dispatch is then resimulated at higher (or lower) load levels, where the hourly load change between the two cases is a fixed amount, such as 10 MW. Estimates of hourly marginal cost, *MEC*, are the differences in hourly total production costs between the two simulations, divided by the magnitude of the load change.[35]

Marginal energy cost also includes non-fuel operations and maintenance expenses ("O&M"), as some non-fuel expenses vary as the output levels of units change. Much of the non-fuel variable O&M expenses, which are incorporated within the marginal energy cost component, are costs associated with plant use attributable to lights, and auxiliary equipment such as fans, blowers, pumps, conveyers for fuel handling, and crushers and pulverizers. Variable O&M costs are highly dependent upon the unit that is on the margin, and estimates reside typically between three and eight percent of average running costs.

Marginal Environmental Cost ("MEN") refers to the incremental cost associated with generating plant emissions, sometimes referred to as environmental externalities. As a matter of definition, environmental costs can be included in forward-looking short-run marginal costs in three ways. First, environmental costs can be defined as the incremental costs that arise from compliance with environmental rules enforced by government authorities such as the Environmental Protection Agency of the U.S. Compliance rules can assume two general types including *physical emission limits*, and *cap and trade programs*. In the case of emission limits, the internal marginal cost to the firm is the *incremental* cost associated with the mitigation of emissions in order to satisfy the compliance rules. Under this approach, incremental compliance costs may be approximately zero in the short run because mitigation strategies, such as retrofitted equipment, are usually indivisible, lumpy investments, where investment costs for compliance do not change with respect to modest-sized changes in the level of output measured in MW.

A second approach to the determination of marginal environmental costs is appropriate under so-called "cap and trade" programs. Under this approach, which is the U.S. approach to managing sulfur dioxide emissions ("SO_2") and nitrous oxides ("NO_x") by power plants in the U.S., the governing authority sets the maximum allowable level of emissions, and then assigns power plants emission permits, where the permits cover allowed emissions at predefined levels—

---

[35] As mentioned, marginal energy cost can be defined as the running costs of the marginal unit during each hour for, say, the baseline case.

usually, observed emission levels for a historical period serve as the baseline level. The limit—which constitutes the "cap" of the "cap and trade" program—may change in future timeframes. Individual power plants must satisfy the limit, but can do so by either limiting the physical quantity of emissions, or by purchasing allowances for emissions in excess of the limits. Because it is less costly for some emitting parties to satisfy the limits than others, they may over-comply, thus freeing excess allowances that can then be sold to parties who find it costly to physically comply. This approach implies that the market value of allowances should approximate the marginal compliance costs. Indeed, if the cap level is set at the marginal damage costs to society from emissions, the market price of allowances also approximates societal damage costs.

The third approach is to utilize estimates of incremental damage costs associated with emissions. Numerous studies of estimates of damage costs associated with *non-market emissions* including that of carbon dioxide ("CO_2"), lead, mercury, carbon monoxide ("CO"), particulate matter, and volatile organic compounds ("VOC") are available, although such studies show widely varying damage costs.

Marginal Capacity Cost ($MC^G{}_h$) is the incremental cost of providing generating capacity and can be developed in two ways. First, marginal capacity cost can be developed from a *planning basis*, where capacity is installed according to explicitly stated reliability criteria. The performance of future generation supply and the levels of hourly demands are uncertain, such that power systems carry reserves in order to ensure sufficient capacity in the face of unexpected supply events, such as forced unit outages, and demand events in the form of unexpectedly high load levels.

Power systems can never be completely reliable and it becomes, moreover, increasingly costly for power systems to maintain progressively greater levels of reserves. Accordingly, power systems generally provide, through a combination of internal resources, firm purchases, and curtailable services, a reasonably optimal level of reserves.[36] Estimates of optimal reserve levels over a forward period, stated as a percentage of peak loads or MW of capability, can be gauged using stochastic methods such as Monte Carlo techniques.

The desired level of reserves can be balanced with the value of reliability to retail consumers, where reliability is measured as the product of the sum of expected unserved energy over some timeframe, and the value of loss load ("VOLL") stated on MWh basis. Essentially, capacity is added to the system up to the point where the value of reliability approximates the incremental cost of capacity for the least-cost capacity option available to the system. The least-cost option is generally a simple cycle combustion turbine unit. Capacity cost is equal to the investment cost per unit of capacity (MW) multiplied by the capital charge rates which consist of an economic carrying charge rate and associated incremental costs covering fixed operations and maintenance expenses, property taxes, administrative and general expenses, and general plant.

---

[36] Planning reserves, which refer to capacity to provide energy and operating reserves, are distinct from operating reserves, which are distinguished by the speed of response to load changes. Some units respond to load changes more or less instantaneously via automatic generation control (AGC) and can thus participate in and provide regulation reserves. Other units provide spinning reserves or can cold-start quickly—*e.g.,* CTs and hydro—thus providing non-spin and supplemental reserves within three to ten minutes.

The second method is a *market-based approach*. Under several regional wholesale markets, so-called installed capacity markets, operated as auctions, have been implemented.[37] The required levels of capacity that service providers must have available are defined by administrative rules. Capacity can be purchased for forward periods through the auctions, or obtained through other means. The auctions serve as the basis to determine (discover) the market value of capacity over forward periods, such as months and years. However, short-term markets wherein capacity can be purchased for a week or so also exist. The prices for capacity within the shorter horizon reflect contemporary supply-demand conditions and, accordingly, tend to show substantial variation over time. It is suitable, moreover, to utilize observed longer-term contract prices for capacity, if the prices do not depart significantly from prices for capacity over timeframe for which marginal costs are being developed. If a market-based capacity cost approach is used, the short-term market value for capacity is preferred, though it requires continued sampling of regional markets, where often capacity prices cannot be readily observed.

In summary, capacity costs, as estimated through planning or market-based methods, can serve as the shadow price of reliability, and can be used in the determination of marginal costs.

Marginal capacity cost can be expressed as follows:

$$MC^G = [I^G * (ECC + R_{fom}) * R] \approx (\sum_h \partial EUE_h / \partial Load_h) * (VOLL/MWh)$$

with,

EUE_h = expected unserved energy, hour h

$VOLL$ = value of lost load to retail customers, per MWh

Load_h = load expressed as a MWh of energy, hour h

MC^G = cost of generating capacity

I^G = investment in the least-cost technology of providing capacity, usually a simple cycle combustion turbine, per MW of capacity

ECC = economic carrying charge rate[38]

R_{fom} = fixed operations and maintenance costs and other capital-related costs, expressed as a percentage of investment cost

---

[37] The structure of regional wholesale markets continues to evolve and, ultimately, capacity markets are likely to be supplanted by implicit scarcity rents, with full content, within the market prices for energy and reserve services. Essentially, expected level of scarcity rent content within markets should approximate the cost of capacity, and where the foregone profits of real power approximate the market prices for reserves. Generators will hold back capacity to provide reserves up to the point where the foregone profits for providing reserves approximate the expected value of the profits associated with real power. The profits arising from the sale of energy in spot energy markets can be viewed as the opportunity costs for providing reserves.

[38] Economic Carrying Charge ("ECC") refers to the annual "all-in" carrying charges on capital including depreciation, payback of principal, interest charges, corporate income taxes where appropriate, and return on capital including investor perceptions of risk. The ECC rate can be calculated as:

$$I \{[(k-i+t)(1+i-t)^n] / (1+k)\}\{(1+k)^m / [(1+k)^m + (1+i-t)^m]\}$$

with I=investment, k=capital charge rate, i=expected inflation, t=technological advance, n=year, m=expected life of capital. CA Energy Consulting has this approach automated within a computer program for expedient calculation of the ECC rate.

R = reserve multiplicative factor, such as 1.15

Marginal capacity cost, MC^G, can then be allocated to hours according to a heuristic allocation function,[39] A_h:

$$A_h = max(0, L^e{}_h - \alpha * L^e{}_p / \Sigma_h\, max(0, L^e{}_h - \alpha * L^e{}_p)$$

with,

α = hourly load distribution coefficient
$L^e{}_h$ = expected load, hour h
L_p = expected peak load within the period

The heuristic approach to capacity cost allocation among hours can work rather well, although estimated hourly expected unserved energy is the preferred allocation approach.

Loss Factors ($LF_{j,h}$), where j covers the various voltage levels is an adjustment to elements of marginal costs in order to reflect all components at the electrical voltage at which electricity service is supplied. In other words, short-run marginal costs for distribution primary voltages will be higher than for transmission service insofar as the total losses at distribution service are larger. The loss factor can be calculated as follows:

$$LF^j{}_h = (1/(1 - ML^j{}_h)) \text{ ,} \qquad \text{with } j = t, d$$

with,

$LF^j{}_h$ = loss factor for transmission (t) and distribution (d) voltages, hour h. Calculated as the marginal losses within a voltage level—*e.g.,* distribution primary or secondary.
$ML^j{}_h$ = thermal line losses on the margin for either transmission or distribution voltages, hour h. Marginal losses are calculated as (∂ Losses/∂ Load)

Marginal Capacity Costs of Transport Services ($C^j{}_h$) with $j = t, d$ for transmission and distribution capacity, respectively, refers to the change in the cost of providing transmission and distribution services in response to a change in load. Transport costs consist of *distance-* and *load-related* dimensions. Load-related transport costs are present in short- and long-run marginal costs, whereas distance-related costs transport costs are present only in the long-run costs. The load-related SRMC of transport services consists of line losses and reliability. Line losses are discussed above. Reliability associated with transport services is conceptually akin to that for generation, where the value of outages to retail consumers can be thought of as the "shadow price" for capacity.

Transmission networks are integrated parts of power circuits, where the circuits also include generators and loads. There are many components to the numerous circuits that constitute large

---

[39] The approach shown is dynamic, and provides capacity prices that will more than recover capacity costs during periods with unexpectedly high loads. Conversely, periods with consistently low loads will, appropriately, under-recover capacity costs. The allocation, however, can be rather static by using $L^e{}_h$ within the numerator rather than day-ahead expected loads, $L^{da}{}_h$. Other approaches are available. For example, if the capacity option is called predominantly during high-load hours, which is likely, the historical frequency distribution of loads within, say, seven percent of the monthly or seasonal peak load value can also be utilized as the basis for hourly cost allocation.

power systems, and the economic costs of the services are highly dependent on status of the many components. Accordingly, reliability costs within transmission networks can be accurately assessed only with highly detailed network models that consider the problem of reliability jointly with generation services and uncertain load levels. A network approach estimates marginal costs by modeling the circuit technology of power supply, where the investment costs associated with changing the circuits are balanced against consumer outage costs and energy line losses. To implement network modeling capability to estimate forward-looking SRMC is a major undertaking.

Distribution reliability costs are equally difficult, although for different reasons. Large differences exist among distribution radial systems, mainly in the form of variation in characteristics including voltage, configuration, redundancy of load-carrying capability, and load density. These differences, coupled with planned redundancy and indivisibility of resources, give rise to great variation in distribution reliability costs. Although reliability costs are likely to be small for virtually all radials within the Barbados power system, some may have very high load-related investment costs.

For forward-looking short-run marginal costs, the analytical complications attending the implementation of an explicit reliability cost-based framework are daunting. Accordingly, the more practical approach is to employ a long-run marginal capacity cost approach. That is, estimate the marginal investment cost of capacity in transmission and distribution, in lieu of the value of reliability characterized as outage costs of consumers. Essentially, the approach is to gauge how expected investment costs are causally linked to expected changes in peak loads.

A long-run capacity cost approach to transport costs precipitates the question of whether or not the long long-run marginal cost framework—*i.e.,* a capacity cost methodology—is a reasonable surrogate for short-run reliability costs. The answer to this question hinges critically on whether or not capacity and its attending costs change with respect to near-term changes in load. The link between contemporary hourly load, L_h, and capacity cost, C^j, needs to be identified and explicitly defined. To elaborate, capacity of transport networks is planned and installed on a basis of expected loads, where service providers form expectations of prospective periods, perhaps over several years ahead. In turn, these expected peak loads, $E(L_{p,y})$ are the basis for T&D capacity plans and resource commitments and investment, I^j. If expected loads are in turn formed from trends in historical peak loads, $L_{p,h}$, the relationship, $I^j = C\{E(L_{p,y}(L_{p,h}))\}$, would seem relevant.

Hence, trends in contemporary historical peak loads ($L_{p,h}$) and investment experience can be used as a surrogate for expected years-ahead peak loads that, in turn, determine the perceived need for changes and additions to T&D capacity, with attending investment costs, I^j.

This capacity approach for transmission and distribution, as a surrogate for short-run reliability costs, can be developed by estimating historical or planned capacity additions as a function of peak loads with statistical analysis, where the result is an estimate of C^j. The annual cost of capacity is as follows:

$$C^j_h = [I^j*(ECC + R^j_{fom}{}^j)/(1 + ECC)] \qquad \text{for } j = t, d$$

with,

C^j_h = transmission (t) or distribution (d) capacity cost, hour h
I^j = investment costs in transmission (t) or distribution (d) resources, respectively
ECC = economic carrying charge rate[40]
R^j_{fom} = fixed operations and maintenance costs, expressed as a percentage of transmission (t) and distribution (d) investment, respectively.

The essential link between incremental capacity costs and contemporary hourly load, L_h, is simply the likelihood that the load in any hour will be the peak load within the contemporary annual period, which then signals capacity changes in prospective years. This relationship is captured with the factor, A_h, shown in the following formulation which is similar to the hourly allocation approach shown above:

A_h = hourly allocator, estimated with the function:[41]

$$max(0, L_h - \alpha * L^e{}_p) / \Sigma_h\, max(0, L^e{}_h - \alpha * L^e{}_p)$$

with,

α = hourly load distribution coefficient
$L^e{}_h$ = expected load, hour h
L_p = planning-based expected peak load

The allocation factor A_h is applied to the estimated transport capacity costs for an annual period (shown above), thus obtaining an hourly estimate of the marginal cost of providing transport services, as follows:

$$C^j_h = [I^j*(ECC + R^j_{fom}{}^j)/(1 + ECC)]*A_h \qquad with\ j = t, d$$

---

[40] Please reference footnote 39.

[41] Please reference footnote 40.

MODEL II: ***Marginal Energy and Outage Costs***[42, 43]

As stated earlier, the so-called **Model II** refers to the approach where outage costs are explicitly modeled rather than using capacity cost surrogates. The example shown below is truncated in its presentation, since marginal energy and environmental costs are reflected in one term, *MEC*. Distribution energy losses are utilized within the presentation below. It is understood that SRMC costs for transmission level service are identical to distribution except for generally lower levels for line losses and *MEUE*.[44]

Shown for secondary distribution service, **Model II** is as follows:

$$SRMC_h^D = (MEC_h * LF^D_{,h}) * (1 - \partial LOLP_h / \partial L_h) + (VOLL - MEC^D_{,h}) * (\partial LOLP_h / \partial L_h) \ ,$$

with,

$SRMC_h$ = short-run marginal cost, hour h

MEC_h = marginal energy cost including the incremental costs of environmental quality degradation, hour h

LF^D_h = loss factor within distribution systems, hour h, equal to $(1/(1-ML^D_h))$

---

[42] The outage costs incurred by consumers, which are inherent in the **Model II** approach, can result from numerous factors, such as exceptionally high load levels, G&T facility failures, inappropriate actions by relay systems, and insufficient redundancy across the entire integrated system, including generation as well as transmission and distribution.

[43] The outage cost approach has close parallels to the capacity cost methodology outlined in **Model I**. Specifically, capacity provides reserves, of course, and should be installed—or contracted for—up to a level that allows the costs of outages to approximate the costs of capacity, at the margin:

$$VOLL * (\partial EUE / \partial Load) \approx I_{g,ct} (ECC + F_{OM}) I \ .$$

[44] This is because the global treatment of outage costs covers the entire integrated system. The *MEUE* implicit within a **Model II** representation of transmission service would not include MEUE attributed to distribution and hence would tend to overstate true outage costs for higher voltages (transmission).

$LOLP_h$ = loss of load probability, hour h. Often estimated with Monte Carlo techniques[45, 46]

L_h = load, hour h

$VOLL$ = value of lost load. Values are specific to the market segment served, and can range from \$1.00/kWh to well over \$10.00/kWh[47]

It is not practical to implement Model II as shown above because the likelihood of not serving load as a result of system failures within transport systems is not sufficiently well understood. Second, the relationship between the likelihood of power outages and system capacity is spatially differentiated and highly specific to location. For this reason, an outage cost approach is typically applied only at the generation level and, as with Model I, marginal costs of transport services are defined in terms of capacity costs.

---

[45] Stochastic methods (*e.g.*, Monte Carlo), as applied to power systems, are challenging insofar as the analysis must account for uncertainty in numerous dimensions including load level, generator unit performance (including partial outages) transmission contingencies, and power availability within the region. Moreover, Monte Carlo assessments of MEUE do not typically incorporate the effects of uncertainty on the marginal fuel costs. Ideally, MEUE should be determined in a manner that accounts for a global representation of uncertainty. Integration of outage cost and energy cost analyses under conditions of uncertainty is the focus of CA Energy Consulting's projects with EPRI, which have developed software to provide estimation capability with location dimensionality. Even this capability, which constitutes a network modeling approach that incorporates the impact of transmission contingency events on MEUE, does not fully capture outage costs. That is, estimation of outage costs should cover the impacts of outages within distribution systems that result from facility failures, relay system errors, faults, and high load levels.

[46] An alternative approach is to apply a function that *assigns* either discrete or continuously variable outage cost values to the individual hours of the day-ahead period according to expected system conditions. Naturally, the hourly outage cost values within the SRMC will often be zero. Under high-load or constrained supply conditions, however, the values can assume higher values depending upon the likelihood of load outages, which generally come in the form of interruption calls or the opening of selected distribution system breakers. The day-ahead conditions which give rise to outage costs greater than zero are often anticipated, and the assessment of the severity of the day-ahead conditions by system operators can be used as a basis for assigning MEUE values.

[47] Outage costs have been extensively studied and a rather rich literature exists. Generally speaking, outage costs are assessed with survey techniques, often referred to as contingent evaluation methods including *willingness to pay* and *willingness to accept* criteria, and demand analysis in the variant, customer preferences for interruptible services.