The Hopkinson Tariff Alternative to TOU Rates in the Israel Electric Corporation

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ABSTRACT

This paper determines three alternative Hopkinson tariffs to replace the Israel Electric Corporation's time-of-use (TOU) energy rate. The first apportions any system residual revenue requirement between customer groups, based on their respective historic peak demands. The second collects the same revenue as the current TOU rates. The third allocates generation revenue requirements for baseload and non-baseload plants in proportion to each class's baseload and non-baseload energy consumption, and allocates transmission and distribution revenue requirements in proportion to each class's connected load. We show that a Hopkinson tariff with demand subscription is an attractive alternative to TOU rates, especially when quantity rationing is essential to maintaining load-resource balance.

INTRODUCTION

Electric utilities commonly price their sales to large industrial customers at seasonal time-of-use (TOU) energy rates that often cause uneconomic bypass and send price signals that may induce inefficient consumption. Real-time pricing (RTP) with spot energy rates that track marginal costs by time and space is efficient, but it is costly for a utility to implement and for its customers to use. These factors have engendered a search by academics and practitioners alike for an alternative to both RTP and TOU energy rates.

The alternative spawning the greatest interest in recent years is a Hopkinson tariff with demand subscription, which dominates TOU pricing in terms of efficiency, reliability management, cost recovery, and prevention of uneconomic bypass (Seeto *et al*., 1997). It effects efficient rationing through demand subscription charges based on marginal capacity costs for generation, transmission and distribution (T&D). It effects efficient consumption through TOU rates set at marginal energy costs. It collects fixed and sunk costs through a connected load charge, and it prevents uneconomic bypass through marginal-cost-based charges for energy and demand subscription. In practice, however, the tariff is complicated to implement. When surplus capacity enables the utility adopting a Hopkinson tariff to maintain almost perfect reliability, it should initially choose one with TOU energy rates and a connected load charge. If the surplus evaporates, the tariff can be augmented with curtailable area-specific rate options that require customer subscription for firm service.

Management in the Israel Electric Corporation of Haifa (IEC) has questioned whether it should replace its industrial TOU energy rates with a Hopkinson tariff. With

an installed capacity of approximately 8,500 MW, the IEC is a government-owned integrated utility that supplies all of the end-use loads in Israel. To provide input into management's decision-making process, we have developed three Hopkinson tariffs as alternatives to replace the IEC's industrial TOU energy rates. The first Hopkinson tariff apportions any system residual revenue requirement between customer groups, based on their respective historic peak demands. The residual revenue is the total revenue requirement, less energy sales priced at the TOU marginal energy costs. The second is a status-quo tariff that collects the same revenue as the current TOU rates. The third tariff allocates generation revenue requirements for the baseload and non-baseload plants in proportion to each class's baseload and non-baseload energy consumption, and allocates T&D revenue requirements in proportion to each class's connected load.

We conclude that RTP based on marginal-cost pricing is an efficient procedure with severe implementation and transaction costs that render it impractical. TOU pricing with energy rates that reflect the utility's expected marginal costs is inefficient, because the system is not perfectly reliable, the utility must recover its costs for financial viability, and because of varying and location-specific distribution costs. We show that a Hopkinson tariff with demand subscription is an attractive alternative to these two options, especially when quantity rationing is essential to maintaining load-resource balance.

THE MARGINAL-COST PRICING PRINCIPLE

Marginal cost (MC) pricing is a fundamental tenet in electricity rate design. The MC price is a market-clearing price that "signals to consumers the costs of producing the last unit of the good," and simultaneously "signals to competitive producers the marginal

benefits of the good to consumers” (Spulber, 1989, p. 234). Electricity demand, however, is time dependent, and so too may be the capacity available to satisfy it. This implies that the "price in each period must equal the conditional expected marginal operating plus rationing costs" (Crew and Kleindorfer, 1976, p. 214), and that marginal capacity costs must be appropriately apportioned (Vardi *et al*., 1977).

TOU pricing, a staple of practitioners and theoreticians alike in both England and France in the 1960's, was "discovered" by America's integrated regulated electric utilities in the 1970's (Joskow, 1976; Acton, 1982). An important advance was that efficient TOU energy rates should track the continuously varying MC in real time to clear spot energy markets (Bohn *et al*., 1984). The resulting RTP scheme is efficient, as it maintains the equality between MC and marginal benefit through its market-clearing prices.

There are, however, both theoretical and real-world caveats that dim the luster of MC-based RTP. The efficiencies of the MC pricing principle might only be realized in a certainty world without externalities, incomplete or asymmetric information, or potentially distortional government rules and regulations (de V. Graff, 1967; Spulber, 1989). And RTP has significant implementation and transactions costs, including costly metering and accounting systems for billing and settlement purposes. It is costly to transmit the spot prices to customers in real time, even if the real-time MC can be accurately computed, and customers must be able to understand and rationally respond to RTP rates in real time. Finally, given the inherent demand and supply uncertainties, periodic quantity rationing is inevitable for the network's safe and reliable operation. Electricity cannot be economically stored, and must be supplied on demand with load-resource balance constantly maintained.

The problems with RTP pricing compound with the global deregulation and restructuring that now marks the industry (Joskow, 1997). Deregulated generation markets are conducive to decentralized ownership and control of plants, and therefore to competitively priced energy that reflects marginal generation costs. Their economies of scale, scope, and density mean that T&D tend to remain monopolistic. Efficient dispatch by a system operator requires a transmission tariff to coordinate the decentralized decisions of buyers and sellers. This tariff can also be MC based, incorporating the marginal costs of generation and line losses, and the opportunity cost created by network congestion (Hogan, 1992). The difference in the spot prices between locations will be the sum of the differences in their marginal line losses and their marginal congestion costs (Bohn *et al*., 1984). Applied to consumption at the distribution level, RTP that reflects TOU energy rates should account for the marginal distribution capacity cost by TOU period. Orans *et al*. (1994) describes a process for quantifying that cost.

In any event, the pervasive transactions and implementation costs of RTP, and the risk of demand-and-supply imbalance cast doubt on its economic efficiency. A limited number of TOU rates based on system MC must be inefficient, because electricity systems are not perfectly unreliable and utilities need to recover large fixed and sunk costs that are not covered by MC pricing when MC is less than average total cost. Location-specific marginal distribution capacity costs further challenge the efficiency of TOU energy rates.

The difficulties with RTP and TOU energy rates have led to a number of alternative proposals. These include priority service and demand subscription service in generation (e.g., Chao, 1983; Wilson, 1993; Woo, 1990, 1991; Spulber, 1992), capacity

reservation for transmission (e.g., Woo *et al*., 1998), and a Hopkinson tariff with demand subscription for distribution (e.g., Seeto *et al*., 1997). Our purpose is to demonstrate the efficacy and construction of a Hopkinson tariff with demand subscription that is specifically designed to solve the problems of excess capacity, high average costs and rates, and the expectation of higher future demands for energy. These are problems faced by the IEC and other integrated electric utilities globally.

THE HOPKINSON TARIFF WITH DEMAND SUBSCRIPTION

A Hopkinson tariff with demand subscription is a forward contract that defines service curtailment conditions and various demand and energy charges. The tariff has three basic components, the first of which is an hourly TOU energy rate that is set at the marginal energy cost. Any geographic differences in marginal line losses, which should reflect the voltage of service, will result in energy rates that differ by location.

The second component comprises three annual subscription charges. The first is a generation demand charge that equals the greater of the expected excess of the hourly outage costs over the hourly marginal energy costs and zero (Woo, 1990). The second is a transmission demand charge that is the lesser of the expected marginal congestion cost and the per kilowatt year (kWy) transmission capacity cost due to new line construction (Nasser, 1999). The third is a distribution demand charge that is the lesser of the expected difference between the hourly outage costs and the hourly marginal energy costs, and the per kWy distribution capacity cost (Ball *et al*., 1997). These demand charges can vary by location, but the generation charge only does so if the marginal energy costs do so.

The third component is an annual connected load charge designed to collect the residual revenue requirements for generation and T&D. The residual revenue for each

function is its revenue requirement less the revenue collected through the other charges. A user's total connected load payment is the per kWy charge multiplied by its historic peak demand. The charge is found by dividing the sum of the three residual revenue requirements by the sum of the users' historic peaks. When only used to collect revenue, the connected load charge does not vary by location. This charge is applicable to a utility with a stable customer base and little load growth. Since the charges are MC based, customers can make economically efficient consumption and subscription decisions, while providing any previously incurred residual revenue requirements. In anticipating the future the charge must also have provisions to deal with customer and load growth. Equity considerations suggest that any new load be assessed a connected load payment that might be discounted if such encourages economic development and reduces other customers' fixed and sunk cost contributions. New customers should also be assessed connected load payments based on estimates of their connected loads. Payments should be “fair,” in the sense that they reflect a new customer’s fair share of the utility’s fixed and sunk costs. By the same token, they should not be so large as to discourage customers from connecting to the network or greatly distort connected-load-size decisions.

IMPLEMENTING THE TARIFF

Retail customers must pay the connected load payment and make demand subscriptions prior to taking service. Customers taking transmission service must also subscribe for generation; those who take distribution service must also subscribe for distribution capacity. When subscribing, customers need to know the probability of curtailment and

the demand charges *ex ante*. Woo *et al.* (1998) describe a posting process for achieving this.

The subscribed demand, or the firm service level (FSL), cannot be curtailed during a capacity shortage. The FSL does not vary by function, because users make no distinction between the causes of a curtailment and the FSL is only firm when sufficient capacity is reserved for all three functions. Subscriptions can be tailored to the user's desired degree of reliability. Shortages do not affect users whose FSLs equal their peak demands; those with zero FSLs risk losing their entire load during a shortage. Hence, customers with higher (lower) outage costs subscribe at higher (lower) FSLs (Chao and Wilson, 1987; Woo, 1990; Spulber, 1992) and receive larger (lower) shares of the limited capacity.

Service begins after a customer makes the connected load payment and pays the demand subscription fee. Absent a capacity shortage, customers can use as much electricity as they desire, so long as they are willing to pay the TOU energy rates. With a capacity shortage, one's load can be limited to the FSL, either at the utility's request, enhanced by a severe non-compliance penalty, or through a remotely activated load-limiting mechanism. Since curtailing *all* customers to their subscribed demands ordinarily leads to excess capacity, service might be curtailed either to a select few users (Chao and Wilson, 1987) or to all users in proportion to their respective FSLs (Spulber, 1992).

Reliable systems, such as that of the IEC, have few locations and sizable marginal transmission congestion costs and marginal distribution capacity costs. Therefore it is unnecessary to develop a full-blown Hopkinson tariff with location-specific demand

subscription charges. To develop a readily implemented rate for the IEC we assume that marginal line losses do not vary significantly by location. This assumption allows us to use the system marginal energy cost in setting the TOU energy rates.

The bill of customer *i* of class *k* in location *j* has three components, the first being a *connected load payment* equal to the product of a network-wide per kW load charge, α_k, and user *i*'s historic peak demand, D_{ikj}. The load charge is the system revenue requirement for class *k*, including a discount for its curtailable load, net of kWh revenue collected from the tariff's TOU energy rates, divided by the total historic peak demand for this class.

The second component is a *discount for the curtailable load*, which is the product of a location-specific discount and customer *i*'s curtailable load. The latter is the difference between D_{ikj} and the subscribed demand, FSL_{ikj}. The former is the sum of the three annual demand subscription charges, denoted β_{ikj}.

The third component is an *energy charge* equal to the sum of the products of the per kWh rate for season *m*, γ_m, and energy consumption during that season, C_m. The most compact form has three seasons: peak, mid-peak, and off-peak. Thus, the customer will be billed a total of:

$$B_{ikj} = \alpha_k D_{ikj} + \beta_{ikj}(D_{ikj} - \mathrm{FSL}_{ikj}) + \Sigma_m \gamma_m C_m.$$

Other charges and bills are compatible with a basic Hopkinson format, but the one proposed for the IEC has several virtues. First, the basic charges of α_k and γ_m do not differ by location and constitute a standard two-part tariff with a connected load and TOU energy charges. Second, the format is a minor modification of a tariff that uses only TOU rates, as holds in the IEC. Third, the utility can selectively decide the locations to

be given a curtailable-load discount, and there will be very few of these with a highly reliable system. The resulting tariff has few location-specific charges and can be quite simple. Last, designating a load to be curtailed through demand subscription can be viewed as a rate option to the basic tariff. Customers desiring the *status quo* need not subscribe.

THE RATE-DESIGN PROCESS

The location-specific discount, β_{ikj}, must be developed on a case-by-case basis and is not considered here. It remains to determine the class revenue requirements for industrial users, the class energy rates, the residual revenue requirement, and the connected load charge per kWy. The design process is straightforward, given the relevant data. Specifically, the class energy revenue is the product of the class kWh sales by TOU and TOU rates equal to the marginal energy costs. The residual revenue requirement is the difference between the class revenue requirement and the class energy revenue. The per kWy charge is determined by dividing the residual revenue requirement by the class total of customer-specific historic peak demands, as recorded in the most recent twelve months. What complicates this otherwise straightforward process is that there are three credible alternatives for determining the class revenue requirement.

The alternative we proposed for the IEC uses a basic Hopkinson tariff. Let ψ denote the historic peak demand for the industrial class as a fraction of the system's total historic peak demands. This alternative sets the industrial class revenue requirement equal to the product of ψ and the excess of the system revenue requirement for generation and T&D over the system kWh revenue.

The second alternative, the *status quo* approach, sets the class revenue requirement equal to the class TOU energy sales by TOU at current TOU energy rates. To apply this approach, one must first determine both the system hourly marginal costs of generation and T&D, and the MC-based class revenue as the annual sum of the products of the class hourly kWh sales and the system hourly MC. The industrial class revenue requirement is the product of the utility's total revenue requirement and the proportion of the total MC-based class revenue accounted for by the industrial class.

The third alternative is based on the utility's capacity planning and recognizes that fixed and sunk costs are incurred to provide reliable service in the face of growing demand. Since T&D capacity is added to serve peak demand growth, it seems reasonable to allocate the T&D requirement based on a class's peak demand (Orans *et al*., 1994). Optimal generation capacity planning, however, dictates that a baseload unit, rather than a peaking unit, be added if the baseload unit yields sufficient fuel-cost savings to offset the difference in the capacity installation costs (Chao, 1983; Wilson, 1993). Since baseload capacity reflects the baseload demand that the utility serves, the revenue requirement for the baseload and non-baseload units can be apportioned to each customer class based on its kWh consumption. To implement this approach, first the revenue requirements by function are determined and the T&D revenue requirements are then allocated to industrial and non-industrial classes in proportion to their respective peak demands. Next, the class-specific baseload energy is computed as the product of the minimum load for the class multiplied by the 8,760 hours comprising a year, and its non-baseload energy is computed as the class total sales for the year less the baseload energy. Third, the revenue requirements for the baseload and non-baseload units are allocated in

proportion to the baseload and non-baseload energies for each class. The sum of the revenue requirements determined in the first and third steps is the class-specific total revenue requirement.

SAMPLE REVENUE ALLOCATION AND TARIFFS

Table 1 reports the revenue requirements for each IEC customer class under each of the three allocation alternatives. Residual revenue allocation using the connected load increases the bills for small users by 16% to 49%, and decreases the bills to large users by 16% to 37%. The *status quo* allocation simply collects the existing class revenues.

To allocate baseload and peak costs based on the baseload and residual energy use of each class, it was assumed that 75% of fuel, operating, and maintenance costs and 10% of generation costs, are related to baseload units. All non-generation costs are allocated based on peak energy use. Baseload consumption is calculated for each as the lowest average demand in any of the nine TOU periods (see Table 2). Wide changes in revenue responsibility result. The bulk low-voltage users are clear winners, and small users are clear losers whose bills increase from 29% to 121%. Table 2 reports three sets of sample tariffs corresponding to the choice of class-revenue allocation method. Under the *status quo*, the demand charge for each class recovers the residual revenue not recovered by its TOU energy rates set at the marginal energy costs of the IEC.

Table 3 compares the three IEC-based high-voltage Hopkinson tariff options of Table 2, translated into $US, with a convenience sample of readily accessible Hopkinson tariffs outside of Israel. This is not necessarily a representative sample, but except for ESKOM and ACETW the data show that many utilities use some form of connected load

charge based on historic peak demand. These data make it apparent that the Hopkinson tariffs that we propose for the IEC are not at odds with what is taking place elsewhere.

CONCLUSIONS

TOU energy rates can cause uneconomic bypass and do not convey the price signals to induce efficient electricity consumption. The inefficiency of TOU rates is compounded when a utility cannot impose a demand-curtailing price premium during periods of excess demand, and instead must ration the limited capacity. The resulting allocation can only be efficient when customers have revealed their preferences for system reliability, but their responses to the TOU rates are uninformative this regard.

The IEC faces precisely this problem, and the solution that we have proposed is a Hopkinson tariff with demand subscription. We have explored three variations on the Hopkinson theme. Our recommended approach apportions the system residual revenue requirement between customer groups in accordance with their historic peak demands. The procedure we have detailed for determining the tariff under each variation is readily implemented, and the resulting tariffs are comparable with those elsewhere in the world. It is our hope and belief that the procedure and the results will be useful to other utilities that are weighing a Hopkinson tariff alternative to their current energy rate packages, and that they will encourage still other utilities to consider the Hopkinson option.

Table 1. Revenue Allocation Impact on Total Group Revenues* (Millions New Shekels)

Allocation Summary	Current	Connected Load Allocation		Status Quo Allocation		Baseload - Peaker Allocation	
	Revenues	Revenue	% Change	Revenue	% Change	Revenue	% Change
Residential	2,960	3,570	20.6%	2,960	0.0%	2,317	-21.7%
Street lighting	114	170	49.1%	114	0.0%	252	120.7%
Small commercial	897	1,038	15.7%	897	0.0%	1,160	29.3%
Bulk (low voltage)	30	19	-36.8%	30	0.0%	17	-42.8%
Bulk (high voltage)	416	326	-21.6%	416	0.0%	328	-21.1%
TOU for low voltage	1,513	1,259	-16.8%	1,513	0.0%	1,776	17.4%
TOU for high voltage	2,175	1,838	-15.5%	2,175	0.0%	2,132	-2.0%
TOU for extra-high voltage	490	368	-24.8%	490	0.0%	606	23.7%

* Excluding consumer revenue.

Table 2: Hopkinson Tariffs by Revenue Allocation Scheme (AG /kWh)

	Smr Pk	Smr Sh	Smr Off	Wtr Pk	Wtr Sh	Wtr Off	Spr Pk	Spr Sh	Spr Off	Demand Charge (N.S./kW-month)
Rates Under Residual Allocation using Connected Load										
TOU for low voltage	18.63	15.18	8.46	19.35	11.87	8.42	16.48	14.24	8.28	16.64
TOU for high voltage	18.25	14.87	8.29	18.95	11.63	8.25	16.14	13.95	8.12	11.39
TOU for extra-high voltage	18.04	14.70	8.20	18.73	11.49	8.15	15.96	13.79	8.02	7.69
Status Quo with No Change in Group Revenue Allocation										
TOU for low voltage	18.63	15.18	8.46	19.35	11.87	8.42	16.48	14.24	8.28	25.93
TOU for high voltage	18.25	14.87	8.29	18.95	11.63	8.25	16.14	13.95	8.12	19.11
TOU for extra-high voltage	18.04	14.70	8.20	18.73	11.49	8.15	15.96	13.79	8.02	20.10
Rates Under Baseload-Peaker Allocation										
TOU for low voltage	18.63	15.18	8.46	19.35	11.87	8.42	16.48	14.24	8.28	35.52
TOU for high voltage	18.25	14.87	8.29	18.95	11.63	8.25	16.14	13.95	8.12	18.12
TOU for extra-high voltage	18.04	14.70	8.20	18.73	11.49	8.15	15.96	13.79	8.02	31.97

Notes: Smr = Summer; Wtr = Winter; Spr = Spring and Autumn;
Pk = Peak; Sh = Shoulder peak; Off = Off peak.

Table 3: Examples of Hopkinson Tariffs (based on the following exchange rates per US$: Canada =1.5; Hong Kong = 7.75; South Africa = 5.835; Australia = 1.5637)

Service Territory	Utility Name	Tariff	Demand charge (US$/kW-month)	Energy charge (US$/kWh)	Connected Load / Ratchet demand provision	TOU Definition
Israel	IEC	Option 1: High Voltage	2.79	.0203 to .0456	Yes	Three seasons, and three TOU period per season
Israel	IEC	Option 2: High Voltage	4.68	.0203 to .0456	Yes	Three seasons, and three TOU period per season
Israel	IEC	Option 3: High Voltage	4.44	.0203 to .0456	Yes	Three seasons, and three TOU period per season
NSW Australia	ACETW	High Voltage Time of Use Demand	4.1 per kVa	.0810 Peak .0685 Shoulder .0418 Off-peak	No	Peak: 7am to 9am; 5pm to 8pm, M-F, non-holiday. Shoulder: 9am to 5pm; 8pm to 10pm, M-F, non-holiday
South Africa	ESKOM	Large Customer Standard	7.083	0.0128	No	
Hong Kong	China Light & Power	Large Power Tariff	14.45 Peak per kVa	0.0657 Peak 0.056 Off Peak	Yes, 50% for summer during prior 12 months	Summer is May to October Off peak is 11pm to 9am and all day Sunday On-Peak is all other hours
British Columbia, Canada	B.C. Hydro	1821	2.94 per kVa	0.0173	Yes, 75% of prior November to February, or 50% of Contract Demand	
Kentucky, USA	American Electric Power	C.I.P. - T.O.D (Primary)	8.60 Peak 2.02 Off-peak	0.0122	Yes, 60% of prior 11 months	Peak: 7am to 9pm, M-F, excluding holidays
Ohio, USA	Ohio Power Company	GS-4 (Primary)	11.470	0.0030	Yes, 100% of prior 11 months	
California USA	Southern California Edison	GS-2	5.4 Ratchet 7.75 Max for the Month	0.0439	Yes, 50% of prior 11 months	
Michigan, USA	Indiana Michigan Power Company	L.G.S (Secondary)	8.920	.04583 Peak .03027 Off peak	Yes, 60% to 25% of contract capacity	Peak: 7am to 9pm, M-F
West Virginia, USA	American Electric Power	I.P. (Secondary)	12.51 Peak 5.5 Off-peak excess	0.0151	Yes, 60% of (contract capacity or prior 11 months)	
Indiana, USA	Indiana Michigan Power Company	I.P. (Secondary)	17.159 per kVa	0.0114	Yes, 60% of Max (contract capacity or prior 11 months)	
Alabama, USA	Alabama Power (Southern Company)	HLF	10.000	0.0046	Yes, 90% of contract capacity or prior 11 months	
Portland, USA	Portland General Electric Company	32	4.3 Peak	.03755 Peak .03255 Off peak	Yes, average of 2 highest in current and 11 prior months	Peak: 6am to 10pm, M-F
North Carolina, USA	Duke Power	I	3.600	0.0329	Yes, contract minimum or 60% or prior 11 months	
Tennessee, USA	Kingsport Power Company (AEP)	I.P. (Primary)	8.7 Peak 2.57 Off-peak excess	0.0230	Yes, 60% of Max (contract capacity or prior 11 months) for Peak	
Calgary, Canada	Enmax	Direct Access Tariff (temporary)	2.00 per kVa	.012 Peak .002 Off Peak	Yes, 100% penalty for usage above contract demand, and reset contract demand to higher value.	Note this proposed rate does not include energy procurement payments
Alberta, Canada	TransAlta	6300	2.633	Winter Summer .0229 .0199 Peak .0222 .0190 Shoulder .0193 .0149 Off Peak	Yes, 100% of prior 11 months	

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