How may a customer exploit the Bonneville Power Administration's new pricing scheme?

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Abstract

For more than half a century the Bonneville Power Administration (BPA) has marketed electricity produced by the Federal Columbia River Power System (FCRPS) to its "preference" customers in the Pacific Northwest. It has historically met the growing needs of its preference customers by augmenting the power provided by the FCRPS with market purchases and recovering its costs through its cost-based rates. The BPA, however, is preparing to implement a new pricing scheme intended to balance its historical commitment to supply its customers with low-cost power from the FCRPS with the need to signal that growing demands are met with increasingly expensive generation resources. This paper describes an opportunity that may exist for customers to exploit the scheme to obtain a larger share of low-cost federal power going forward. We show that when all customers take advantage of the opportunity, they find themselves in a form of the Prisoner's Dilemma whose outcome is a lose-lose Nash equilibrium, and discuss its managerial implications.

Keywords: electricity pricing; Bonneville Power Administration; Prisoner's Dilemma

1 Introduction

For more than half a century, the Bonneville Power Administration (BPA), created by Congress in 1937 as a not-for-profit federal agency under the Department of Energy, has marketed power from the Federal Columbia River Power System (FCRPS), a collection of hydroelectric dams and other generation resources in the Pacific Northwest (BPA, 2003). As a federal agency with public-service commitments and objectives, the BPA strives to sell electricity at the lowest possible cost-based rates to its "preference" customers. These customers include non-profit municipal utilities, public-utility districts, rural electric cooperatives, and federal agencies located in the BPA's vast service area of Washington, Oregon, Idaho, and contiguous portions of Montana, Wyoming, Utah, Nevada and California in the Columbia River watershed. In doing so, the BPA seeks to maximize the benefits to its customers, who will in turn sell the electricity to *their* final consumers or end-users.

Low-cost federal power has been a key driver in the economic development of the region, enabling it to attract electricity-intensive industries such as aluminum production, airplane manufacturing and, today, server farms. The FCRPS produced over 79,000 gigawatt-hours (GWh) of electricity in 2008, generating $3 billion in operating revenues (BPA, 2009a). The BPA's 147 public agency customers provide retail electric service to over 10 million people in the Pacific Northwest. The BPA also provides bill-reduction benefits to residential and small-farm customers of investor-owned utilities in the region.

The BPA is obligated to meet the net requirements, or retail electric loads net of any owned generation, of its preference customers with federal power from the FCRPS. Continuing demand growth among these customers, however, coupled with increasing operating restrictions imposed to protect fish populations along the FCRPS waterways, is beginning to constrain the BPA's ability to reliably meet its customers' growing electricity needs. In recent years, the BPA has met this challenge by augmenting the power provided by the FCRPS with market purchases as necessary and recovering its costs through its wholesale rates, which do not vary by consumption level. In the period immediately following the electricity crisis of 2000-2001 (Woo, 2001), however, the BPA came under growing pressure to find a way to limit its sales of cost-based power to the firm supply capability of the FCRPS, thereby placing growing customers in a position of paying the full cost of new resources for their incremental demands.

After a four-year public dialogue among the BPA and stakeholders (including BPA customers, state agencies, environmental advocates, ratepayer representatives, and others), in September 2009 the BPA announced its Tiered Rate Methodology (TRM). This is a new pricing scheme under which a BPA customer will be charged at a market-based Tier-2 rate for its incremental consumption above its allocation of the BPA's existing generation. Billed at a low Tier-1 rate reflective of the BPA's average cost, the customer-specific allocation is the customer's *pro rata* share of all BPA customers' consumption recorded in 2010, *after* the BPA's TRM announcement. This gives rise to an opportunity for the customer to exploit, at the expense of other BPA customers, the BPA's new pricing scheme.

The purpose of this paper is to develop an optimal multi-period purchasing *and* retail-pricing strategy for an electricity distribution utility's management in an uncertain demand and wholesale-price environment. We accomplish this through the backward solution to a two-stage dynamic-programming model under uncertainty. In the second period, management makes its purchase decisions so as to maximize its end-users' expected welfare, net of the costs of the utility's power purchases, since the end-users ultimately incur those costs through the rates they pay for their electricity. In the first period, with the second-period's upcoming decisions taken into account, management seeks to maximize the *sum* of its end-user's net expected welfare from its first-period purchases and the discounted second-period net expected welfare. The first-period net expected welfare must take into account both the uncertain first-period weather and what, at the beginning of the first period, is the uncertainty as to the second-period Tier-1 and Tier-2 rates.

Our analysis exposes the incentive for a BPA customer to exploit the BPA's new pricing scheme. The customer's efforts would likely be ineffective if all BPA customers adopt the dominant strategy of increasing their period-1 sales to their end-users, as no customer would be able to significantly increase its period-2 share of the BPA's low-cost supply from the FCRPS. This is the case, because the customers are likely to find themselves embroiled in a form of the classical Prisoner's Dilemma whose outcome is a Nash equilibrium that is unsatisfactory to all parties (Luce and Raiffa, 1957, pp. 94-95). The BPA, however, recognizes that not all customers would adopt this dominant strategy; and it has correctly included in its scheme a provision to reduce the period-2 allocation of a customer found to have unreasonably exploited the TRM.

2 Literature review

The new pricing scheme responds to criticisms of the BPA selling electricity at rates that are below the competitive market prices (Cavanagh, 1983; Houston, 1996; Antonelli, 1998; OECD, 2006; BPA Watch, 2009). Our analysis of this scheme is related to the more general restructuring of electricity markets so as to introduce wholesale-generation market competition in North America and beyond (Sioshansi and Pfaffenberger, 2006). Wholesale electricity spot-market prices are inherently volatile and spiky, thanks to daily fuel-cost variations, weather-dependent and time-varying demands that must be met in real time by generation and transmission already in place, unexpected failures of electrical facilities, and lumpy capacity additions that can only occur with a long lead time (Li and Flynn, 2006; Tishler et al., 2008). Poor market designs and market-power abuse by generators exacerbate spot electricity price volatility and spikes (Borenstein et al., 2002)

There is extensive empirical research on electricity spot-price behavior and dynamics (e.g.: Bessembinder and Lemmon, 2002; Longstaff and Wang, 2004; Knittel and Roberts, 2005; Haldrup and Nielsen, 2006; Mount et al., 2006; Park et al., 2006; Karakatsani and Bunn, 2008; Marckhoff, and Wimschulte, 2009; Redl et al., 2009). An important application of this research is risk management by an electricity utility that seeks to minimize its procurement cost variance subject to a cost-expectation constraint (Woo et al., 2006; Deng and Oren, 2006; Deng and Xu, 2009; Huisman et al., 2009). To complement its risk management, the utility adopts a pricing scheme to pass the procurement cost risk to its customers, as well as to promote conservation behavior (Woo and Greening, 2010).

The BPA's pricing scheme is also related to two-part electricity-rate designs that implement marginal-cost pricing without significant bill impacts on customers (e.g., Orans et al., 2010). In particular, a BPA customer's Tier-1 charge is the BPA's average embedded cost rate times the customer's own allocation of the Tier-1 quantity; and the customer's Tier-2 rate is the competitive wholesale market price. The BPA's pricing scheme, however, differs from these two-part designs in one important aspect. Under the BPA's scheme the customer's Tier-1 allocation for the next period (year 2011) depends on its purchases in the current period (year 2010). In contrast, a typical two-part design has a Tier-1 quantity tied to the customer's historical consumption, which is not subject to exploitation by a customer through its current consumption decision (Taylor et al., 2005).

3 BPA's Tiered Rate Methodology (TRM)

In anticipation of the expiration of the great majority of its power sales contracts in 2011, in 2005 the BPA initiated a "Regional Dialogue" process to address its post-2011 power-supply role (http://www.bpa.gov/power/PL/regionaldialogue/). This process culminated in September 2009, when the BPA issued its TRM, which establishes each customer's allocation of low-cost power from the FCRPS based on expected production under "critical water" as defined by the severe drought conditions of October 1936 to September 1937 (BPA, 2009b). The allocation is to be based largely on each customer's 2010 federal power requirements, termed the customer's "High Water Mark," relative to FCRPS production under critical water. Starting in 2011, each customer will receive an allocation of this low-cost "Tier-1 power" based on its 2010 High Water Mark.

Electricity procured by a BPA customer to meet its resale obligation to its end-users in excess of the customer's Tier-1 allocation is referred to as "Tier-2 power." The customer must purchase its Tier-2 power from the BPA or, alternatively, deliver it at a constant flat rate (i.e., one mega-watt-hour (MWh) of electrical energy delivered per mega-watt (MW) of capacity per hour) to the BPA system. These requirements allow the BPA to flexibly use its vast hydro resources to meet the customer's fluctuating hourly demands within a day. Irrespective of the source of the Tier-2 power, the customer's incremental procurement cost reflects the price of the Mid-Columbia (Mid-C) wholesale electricity market in which the BPA transacts (Woo et al., 2007). The BPA also offers a Shared Rate Plan (SRP) that melds the Tier-1 and Tier-2 rates, but this plan only applies to its smallest customers. Hence, our focus is the incentives inherent in the tiered-rate structure, not the SRP.

4 Model

At first blush, utility management would seem to be facing a rather simple two-step decision problem under the TRM: determine how much electricity the utility's end-users will require and then purchase its maximum allocation from the BPA and the rest as Tier-2 power. That requirement, however, will depend, among other things, upon the weather, which can always be trusted to be unpredictable. Thus, even in the simplest framework of a one-shot decision, a risk-neutral utility management is facing a decision problem under uncertainty in which it seeks to make its purchases to maximize the *expected* net welfare of those purchases to its end-users, with the BPA Tier-1 rate, the Tier-2 rate, and its allocation as known parameters.

Because each utility's future allocation is determined by its current consumption, however, utility management is forced to recognize that it is not making a one-shot decision. Rather, decisions that it makes leading up to and during the 2010 purchasing period will impact its Tier-1 allocation in the subsequent purchasing periods of 2011 and beyond. Moreover, that recognition is accompanied by the introduction of two additional sources of uncertainty: notably, uncertainty about the Tier-1 and Tier-2 rates in that subsequent period.

Consider a two-period model in which J BPA customers take advantage of the opportunity to satisfy their full period-1 power requirements by purchasing on behalf of their retail end-users Q_{j1} ($j = 1,\ldots, J$) MWh of electricity from the BPA at R_1, the BPA's average embedded cost rate for its own generation. Based on BPA (2009a), R_1 is assumed to be below the prevailing spot price of P_1.

It is reasonable to assume each customer to be a full-requirement customer that satisfies 100% of its first-period resale obligations to its end-users through the BPA. This is so, even if Customer j can *partially* self-supply through its own generation assets or by signing power-purchase agreements with other generators, since it will still find it profitable to cover its net short position, which is the positive difference between its resale obligation and its ability to self-supply, through power purchased from the BPA at the rate of $R_1 < P_1$. We also assume that Customer j will not arbitrage by turning around and profitably selling its BPA power in the wholesale competitive generation market. This assumption is reasonable, because arbitrage by a customer can jeopardize its relationship with the BPA.

In accordance with the BPA's current policy, in the second period Customer j receives a maximum MWh allocation of $A_{j2} = K_m(Q_{j1}/Q_1)$, where K_m denotes the minimum output from the BPA's hydro generation, and $Q_1 = \Sigma_j Q_{j1}$ is the total period-1 power purchased by all J customers. In the second period, the BPA charges a rate of R_2, which is again less than the wholesale market price of P_2. The BPA determines that rate via $R_2 = [F - (K_{2H} - K_m)P_2]/K_m$, where F is the revenue requirement for the BPA's existing generation, and K_{2H} is the BPA's period-2 hydro output. Since $(K_{2H} - K_m)P_2$ is the revenue from the BPA's sale of unallocated hydro output into the wholesale market,

R_2 is the BPA's net revenue requirement of $[F - (K_{2H} - K_m)P_2]$ per unit of minimum output K_m.

We assume both K_m and P_2 to be uncertain at the inception of the two-period decision process. Hence, in the first period utility managers treat them as random variables. That treatment, along with the period-1 weather, in turn makes the period-2 rate of R_2 a random variable for purposes of period-1 decision making. By the start of the second period, however, the uncertainty has been resolved, based on the BPA's knowledge of water storage and the wholesale forward price at the end of the first period. Thus, the weather now becomes the sole source of uncertainty.

Each management's two-stage problem is to determine both period-1 purchases from the BPA of Q_{j1} and period-2 purchases of Q_{j2}, so as to maximize the net expected welfare of those purchases to its customers. The major *substantive* difference between management's two-period problem and its period-2 problem is the need to take into account at the outset the impact that the period-1 purchase will have on its period-2 BPA allocation. We therefore attack this two-stage dynamic-programming problem through backward induction, first solving the simpler period-2 problem.

5 The second-period problem

In the second period, each of the BPA's J customers will make consumer-welfare-maximizing Tier-2 purchases of $(Q_{j2} - A_{j2})$ MWh for retail consumption, after realization of its period-2 allocation of A_{j2}, the BPA's period-2 Tier-1 rate of R_2, and the period-2 Tier-2 rate of $P_2 > R_2$. We assume that the Tier-2 rate and wholesale market price are equal at P_2 to prevent arbitrage opportunities.

Let $V_{j2} = v_2(Q_{j2}, \omega_2)$ denote the "social" welfare function from retail consumption of Q_{j2} MWh of electricity by consumers served by Customer j, where ω_2 denotes the uncertain weather conditions under which that consumption will take place. We assume $v_2(Q_{j2}, \omega_2)$ to be an increasing and strictly concave function of Q_{j2}, which implies a positive and diminishing marginal benefit of $\partial v_2/\partial Q_{j2}$ from additional retail sales to Customer j's end-users. We conjecture that for any given level of those sales, consumer welfare will be reduced by severe weather conditions. Thus, supposing 65 degrees Fahrenheit to represent an ideal temperature, consumer welfare will decline monotonically as the temperature either falls below or rises above that benchmark. The conjecture, however, is unnecessary for the analysis that follows.

A risk-neutral Customer j determines its pricing rule by choosing Q_{j2}, so as to maximize the net expected welfare of the consumers it serves, which is denoted π_{j2}. The expectation is taken with respect to the uncertain ω_2, which, like the other uncertain elements in our scenario, management is assumed to treat as a random variable for which it has assessed a probability density with given mean and variance. The expected welfare is denoted $E_\omega[V_{j2}]$. The customer's electricity purchase payment, which is to be netted out, is the sum of its payments to the BPA and to wholesalers. The latter is given by $R_2A_{j2} + P_2(Q_{j2} - A_{j2})$. Hence Customer j's period-2 objective function is:

$$\pi_{j2} = E_\omega[V_{j2}] - R_2A_{j2} - P_2(Q_{j2} - A_{j2}) \quad . \tag{1}$$

The first-order condition for a maximum with respect to Q_{j2} is:

$$\partial\pi_{j2}/\partial Q_{j2} = \partial E_\omega[v_2] /\partial Q_{j2} - P_2 = 0. \tag{2a}$$

The strict-concavity assumption for the welfare function assures that the second-order condition for a maximum is satisfied. Therefore the first-order condition for a net-expected-welfare maximum reduces to:

$$\partial E_{\omega}[v_2]/\partial Q_{j2} = P_2 \quad . \tag{2b}$$

That is, Customer j sets its period-2 marginal retail rate at $P_{R2} = P_2$ in accordance with marginal-cost pricing (Laffont, 1988), P_2 being its marginal cost of acquiring Tier-2 electricity. This is because their rational retail consumers will be willing to pay a retail price of P_{R2} that equates to the expected marginal benefits that they will reap from their electricity purchases.

Pricing all retail consumption at $P_{R2} = P_2$, however, leads to over-collection of revenues. Specifically, Customer j will collect P_2Q_{j2} for electricity from consumers, but will only have spent $R_2A_{j2} + P_2(Q_{j2} - A_{j2}) = P_2Q_{j2} + (R_2 - P_2)A_{j2}$ in the acquisition of that electricity. Since $(R_2 - P_2) < 0$, Customer j is making a profit, which is not permitted by its charter. To deal with this situation, Customer j can implement an inverted block retail tariff to match its procurement payment (Herriges and King, 1994). The first block's retail rate is R_2 for block-1 retail sales that sum to A_{j2}. The second block's retail rate is P_2 for consumption above the block-1 MWh allowance. This retail pricing scheme is subject to a further qualification. In particular, if all consumers are similar in their MWh purchases, then the first block's MWh quantity is the Tier-1 allocation divided by the number of retail consumers, so that each benefits equally from the BPA's largesse. If, however, end-users have diverse sizes, then it may be necessary to develop the first-block allowances by consumption band.

Finally, invoking the Envelope Theorem and letting Q_{j2}^* denote the optimal period-2 electricity sale to its retail customers, it is immediately seen that the welfare effect of an increase in Customer j's allocation is:

$$\partial \mathrm{E}_{\omega}[v_2(Q_{j2}^*, \omega_2)]/\partial A_{j2} = P_2 - R_2 > 0. \tag{3}$$

That is, the expected marginal benefit to end-users of, say, a unit increase in Customer j's allocation from the BPA will be the per MWh cost saving of $(P_2 - R_2)$ that is passed on to Customer j's end-users.

7 The first-period problem

At the start of the first period, full-requirement BPA Customer j makes its decisions to maximize the net expected total welfare for both periods. This total welfare comprises two parts. The first part is the expected consumer welfare of $\mathrm{E}_{\omega}[V_{j1} = v_1(Q_{j1} = A_{j1}, \omega_1)]$ from the purchase of $Q_{j1} = A_{j1}$ MWh of electricity from the BPA, under the uncertain period-1 weather conditions for which management has assessed a probability density with given mean and variance. Under the full-requirement assumption, the period-1 net expected welfare is given by:

$$\pi_{j1} = \mathrm{E}_{\omega}[V_{j1}] - R_1 Q_{j1}. \tag{4}$$

The second part is the net expected period-2 welfare, discounted at the utility's discount rate of δ_j. Assuming the utility management to quantify its period-1 uncertainty as to the period-2 Tier-1 and Tier-2 rates through probability densities with given means and variances, this expectation is:

$$\mathrm{E}_{R,P}[\mathrm{E}[\pi_{j2}]] = \mathrm{E}_{\omega}[V_{j2}] - \mathrm{E}_{R}[R_2]A_{j2} - \mathrm{E}_{P}[P_2](Q_{j2}^* - A_{j2}). \tag{5}$$

We further assume that in making its probability assessments, management takes the BPA pricing policy into account, so that the densities are not statistically independent and their means are assigned to satisfy $E_P[P_2] > E_R[R_2]$.

Customer j now determines its period-1 purchases and pricing rule by choosing Q_{j1} so as to maximize an objective function of $\pi_{jT} = \pi_{j1} + \delta_j E_{R,P}[E[\pi_{j2}]]$; or:

$$\pi_{jT} = E_\omega[V_{j1}] - R_1 Q_{j1} + \delta_j\{E_\omega[V_{j2}] - E_R[R_2]A_{j2} - E_P[P_2](Q_{j2}^* - A_{j2})\}. \quad (6)$$

Although at a glance Equation (6) looks somewhat daunting, recognizing that the only two-stage decision variable is Q_{j1} relieves any preliminary anguish. First differentiating the non-discounted period-1 terms we obtain:

$$\partial E_\omega[v_1]/\partial Q_{j1} - R_1. \quad (7a)$$

To differentiate the discounted period-2 terms, it is helpful to also recognize that the only variable that is directly impacted by Q_{j1} is A_{j2}. The optimal period-2 purchase total, Q_{j2}^*, is fixed by Equation (2b). The only issue is how much of that total Customer j will acquire at the Tier-2 rate.

As to A_{j2}, its relationship to Q_{j1} is given by $A_{j2} = K_m(Q_{j1}/Q_1)$. Therefore the derivative of the discounted term with respect to Q_{j1} is given by:

$$(E_P[P_2] - E_R[R_2])\partial A_{j2}/\partial Q_{j1}. \quad (7b)$$

It is easily seen that:

$$\partial A_{j2}/\partial Q_{j1} = K_m\{Q_1 - (\partial Q_1/\partial Q_{j1})Q_{j1}\}/Q_1^2. \quad (7c)$$

Letting $\theta = K_m/Q_1 > 0$, or the ratio of the BPA's period-2 minimum output to its period-1 sales, and $0 < \varepsilon_j = (\partial Q_1/\partial Q_{j1})(Q_{j1}/Q_1) < 1$, or the elasticity of the BPA's period-1 sales with respect to Customer j's period-1 purchase, Equation (7c) may be written as:

$$\partial A_{j2}/\partial Q_{j1} = \theta(1- \varepsilon_j). \quad (7d)$$

If other customers do not react to Customer j's purchase decisions, then $\partial Q_1/\partial Q_{j1} = 1$ and $\varepsilon_j = Q_{j1}/Q_1 = s_j$, which is Customer j's period-1 full-requirement purchase from the BPA as a share of the BPA's total period-1 electricity sales.

The BPA serves over 100 relatively small municipal utilities and cooperatives, none of which dominates the others in size. This allows one to surmise that ε_j is equal to s_j and other customers do not react to Customer j's actions. Therefore, letting $\eta = \mathrm{E}_P[P_2] - \mathrm{E}_R[R_2]$, and with the appropriate substitutions into Equation (7a) and Equation (7b), followed by minor manipulation, the first-order condition for a net-expected-welfare two-period maximum may be written as:

$$\partial \mathrm{E}_\omega[v_1]/\partial Q_{j1} = R_1 - \delta_j \eta \theta (1 - s_j). \tag{8}$$

Our strict-concavity assumptions assure that the second-order conditions for a maximum are satisfied where Equation (8) holds.

Reasoning as we did in the period-2 analysis that followed Equation (2b), Customer j will set its period-1 marginal retail rate at $P_{\mathrm{R}1} = R_1 - \delta_j \eta \theta (1 - s_j) < R_1$. This is because its rational retail consumers will be willing to pay a retail rate of $P_{\mathrm{R}1}$ that equates to the expected marginal benefits of $\partial \mathrm{E}_\omega[v_1]/\partial Q_{j1}$ that they will reap from their electricity purchases.

8 The dominant strategy

We recognize that Customer j may not be the unique customer aware of its potential use of its period-1 retail sales to increase its period-2 allocation. Indeed, suppose that an equal-sized Customer k follows the same two-stage decision-making analysis as we have projected for Customer j. Assume further that these are the *only* two customers served by the BPA. In that case, both customers receive equal allocations in the second period as had been projected in their period-2 analyses, with the same welfare implications, but the end-users that each serves suffer a diminution of period-1 welfare because each customer's BPA purchases is above the period-1 welfare-maximizing level at $P_{R1} = R_1$.

Suppose, then, that *neither* customer is aware of our analysis and thus that both make single-period decisions as the occasions arise. In that case, we have the status quo.

If, however, Customer *j* is alone in taking a two-stage approach to its decision problem, it will achieve for its end-users a net expected total welfare gain of $(\delta_j \Delta\eta - \lambda_j) > 0$, where Δ is the increased period-2 allocation and λ_j is the small period-1 welfare loss described above. Thus, Customer *j*'s net gain is (a) $\delta_j \Delta\eta$, the discounted value of its expected welfare gain from buying additional units in period two at the BPA's cost-based Tier-1 rate, net of (b) λ_j, its period-1 cost to obtain (a). For its part, a blithely oblivious Customer *k* will suffer a reduction of Δ in its period-2 allocation, and hence its customers will suffer an expected loss of $\delta_k \Delta\eta$.

The customers' problem results in a form of the classical Prisoner's Dilemma, as summarized in Table 1. The payoffs in Table 1 are derived from the following four cases:

- Case 1: Both customers use the single-period decision-making strategy. Neither customer gains since their period-2 allocations from the BPA remain unchanged. Hence, the payoffs for the (Single-period, Single-period) cell are (0, 0).
- Case 2: Customer *j* uses the single-period strategy and Customer *k* the two-period strategy. Customer *j*'s payoff is $-\delta_j \Delta\eta < 0$ because of Customer *j*'s loss in its period-2 allocation. Customer *k*'s net gain is $(\delta_k \Delta\eta - \lambda_k) > 0$, after accounting for its period-1 cost λ_k. Hence, the payoffs for the (Single-period, Two-period) cell are $(-\delta_j \Delta\eta, \delta_k \Delta\eta - \lambda_k)$.

- Case 3: Customer *j* uses the two-period strategy and Customer *k* the single-period strategy. This case is analogous to Case 2. Customer *j*'s payoff is $(\delta_j \Delta\eta - \lambda_j) > 0$ and Customer *k*'s $-\delta_k\Delta\eta < 0$, implying that the payoffs for the (Two-period, Single-period) cell are $(\delta_j \Delta\eta - \lambda_j, -\delta_k\Delta\eta)$.
- Case 4: Both customers use the two-period strategy. Since there is no change in each customer's period-2 allocation, despite the period-1 cost, the payoff for the (Two-period, Two-period) cell are $(-\lambda_j < 0, -\lambda_k < 0)$.

Table 1: Payoffs of a customer's decision-making strategy

Decision-making strategy of Customer *j*	Decision-making strategy of Customer *k*	
	Single-period	Two-period
Single-period	(0, 0)	$(-\delta_j \Delta\eta, \delta_k \Delta\eta - \lambda_k)$
Two-period	$(\delta_j \Delta\eta - \lambda_j, -\delta_k\Delta\eta)$	$(-\lambda_j, -\lambda_k)$

The payoffs in Table 1 suggest that the dominant strategy for either customer is to use the two-period strategy, resulting in no customer substantially gaining period-2 allocation at the expense of another customer. In the absence of changes in the structure of the problem to allow for, say, sequential decision making and the exchange of information (e.g.: Clark and Sefton, 2001; Ahn et al., 2007; Szolnoki et al., 2008), the result is a Nash equilibrium that generalizes to the case of many customers.

9 Managerial implications

More than a century ago, Thorsten Veblen discussed the behavior of business enterprises as a game in which "Captains of Industry" are designing and making strategic decisions commonly directed against each other (1904, pp. 27-35). Forty years later, John von Neumann and Oskar Morgenstern (1944) provided the formal structure that houses a vast array of managerial decision-making problems which, when couched in oligopolistic contexts such as the one that we have described, have resulted in similar Prisoner's Dilemma frameworks that may have dissimilar managerial implications. Brander and Spencer (1983), for example, determine that the strategic use of R & D is inefficient in that the rivals' total costs are not minimized although net welfare may increase. By contrast, Röller and Tombak (1990) show that consumers can benefit from the introduction of flexible production technologies, and managers have been shown a tendency to "over-compete" in their pricing decisions (Griffith and Rust, 1997), while Chen et al. (2001) determine that a Prisoner's Dilemma only occurs when individual consumers are particularly susceptible to being "targeted" by marketing managers. In related work, Choudhary et al. (2005) demonstrate through the Prisoner's Dilemma that in vertically differentiated industries, such as IT hardware, it is critical for managers to keep in mind the interplay between market coverage, intensified competition, and the shape of the cost function.

A ubiquitous array of issues, particularly involving retailers, are explored in such game-theoretic settings, most notably the Prisoner's Dilemma, in Greenwald and Kahn (2005). And surely of greatest currency, Cheng et al. (2011) through the dilemma conclude in a forthcoming important public-policy-related paper that under net neutrality the broadband provider will invest in "broadband infrastructure at the socially optimal level."

Our paper adds to this literature in showing that despite BPA management's best intentions, when both (or all) of its customers behave so as to maximize *their* end-users' expected welfare, and do so by paying due diligence to the fact that their decisions have inter-temporal consequences, the overall result is one that *none* of the protagonists desires: notably, a welfare loss. From a general policy-making standpoint that extends beyond the electric-utility industry, our analysis makes clear that management with federally-mandated responsibilities (principal) must consider the consequences of their policy choices by accepting as a working hypothesis that the decision makers (agents) whom those policies will impact will make *their* decisions with an eye towards their long-term consequences (Laffont and Martimort, 2002). In that case it may well be that consumers will benefit when the invisible hand that guides the market is encouraged to move in certain directions and dissuaded from moving in others. To be sure, the agents impacted by those policies must also recognize that any current decision can have long-term consequences, and whatever they might want to believe they are unlikely to be cleverer than anybody else. Thus, avoiding the lose-lose outcome might require changes in organizational norms and the replacement of opportunistic behavior in the repeated interactions of market agents (Kolstad, 2007, p. 70), and/or identifying “where to focus efforts to improve alliance cooperation and performance” (Arend and Seale, 2005. p. 1057).

Most particularly, the analysis highlights sensible rate-making principles that are commonly used by electric utilities. First, an electric-rate design should reflect the marginal procurement cost of supply, as exemplified by the BPA’s TRM and second-period rate. Second, when managements are risk-neutral, uncertainty – i.e., the weather and spot-market behavior - does not alter the principle of marginal-cost pricing. Finally, when formulating a new pricing scheme it is necessary to consider possible customer responses that may compromise the intent effectiveness of the scheme, when customers are thinking along lines in which they have been trained to think.

10 Conclusion

The BPA was established with the very best of intentions: notably, to provide end-users in the Pacific Northwest with hydro-generated electric power at the lowest possible cost-based rates. Municipal utilities and cooperatives in the region operate with the same good intentions. Our analysis reveals, however, that when utility managers are cognizant of the BPA's allocation and rate-making policies, their decision making in a dynamic world can encourage them to adopt a multi-period strategy, so as to promote their period-1 retail sales to increase their period-2 allocation from the BPA. If all utility managers anticipate actions by others, a dominant strategy is to adopt the two-period decision-making stratagem that results in no customer being able to substantially increase its period-2 allocation at the expense of another customer.

The BPA fully understands the sales promotion incentives in its new pricing scheme. It also recognizes the possibility that not all utility managers would adopt the optimal two-period decision-making strategy, in which case some of its customers may successfully exploit the TRM as the expense of other customers. For this reason, the BPA has correctly included in its TRM a provision to reduce a customer's period-2 allocation to "account for customer's actions or inactions, including both intentional and unintentional acts and omissions, that increase its FY 2010 loads through practices that are outside of accepted, prudent utility standards and practices or actions that are undertaken for the purpose of establishing a larger [allocation] than the customer would otherwise have" (BPA, 2009b, p.30).

Going forward, what should a BPA customer do in light of the TRM? There are several fruitful actions that the customer may take, including: (a) developing strategies to hedge against the Tier-2 rate and volume risks; (b) evaluating competitive procurement of forward contracts and tolling agreements to displace Tier-2 purchases from the BPA; and (c) implementing economically sensible pricing to signal marginal procurement cost to its end-use consumers. Indeed, these are the actions that have been undertaken by some BPA customers and whose study are the subjects of our on-going research agendas.

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