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**PUBLIC DOCUMENT  
TRADE SECRET DATA EXCISED**

December 31, 2014

**VIA EMAIL  
AND FEDERAL EXPRESS**

Darrell Nitschke, Executive Secretary  
North Dakota Public Service Commission  
Department 408  
600 East Boulevard Avenue  
Bismarck, ND 58505-0480

RE: COMPLIANCE REPORT ON RESIDENTIAL TIME OF DAY SERVICE  
CASE NO. PU-12-813

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy, submits the attached Compliance filing pursuant to the *Order Adopting Settlement*, dated February 26, 2014, issued by the North Dakota Public Service Commission in the case referenced above.

The Commission's Order directed the Company to investigate the feasibility of redesigning our current Time of Day (TOD) rate. The objective of a new TOD rate would be to provide accurate and clear price signals to customers, help to reduce North Dakota's contribution to the Company's peak periods, and minimize the incremental costs to administrate the TOD rate. The Company agreed to submit either a pilot TOD tariff or a recommendation regarding an appropriate path for improving a residential TOD offering in North Dakota.

For the reasons listed in the report, the Company is recommending that the current TOD rate offering remain in place. The Company will continue to monitor the effectiveness of its TOD rate within the context of the existing energy market conditions, new metering technologies, and customer preferences.

Portions of this report have been designated as “Non-Public” because it contains information the Company considers to be trade secret data pursuant to NDCC Sections 44-04-18.4 and 47-25.1-01. The information contains sensitive marginal price data that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from their use. Thus, Xcel Energy maintains this information as a trade secret. This designation is made pursuant to the Commission’s Order Granting Trade Secret Protection dated August 26, 2013.

Please contact me if there are any questions concerning aspects of this filing at 701-241-8632.

Sincerely,



David H. Sederquist  
Sr. Regulatory and Financial Consultant

Enclosures



**Assessment of the Need to Revise  
Residential Time-of-Day Service  
In North Dakota**

*for*

**Xcel Energy, Inc.**

*December 31, 2014*

Christensen Associates Energy Consulting, LLC  
800 University Bay Drive, Suite 400  
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## EXECUTIVE SUMMARY

### Context

In recent years the Staff of the North Dakota Public Service Commission have explored various residential time-of-day (TOD) rate offerings in place throughout the country. Xcel Energy and other utilities in North Dakota have been encouraged to consider revisiting their own TOD rates to look for opportunities to make them more attractive to residential customers and to improve the Company's overall load factor in the state. Xcel Energy's existing residential TOD tariff has attracted few customers. In response, the Company agreed to a provision in the Settlement Agreement in Case No. PU-12-813 to investigate the feasibility of redesigning its current TOD offering to customers and file a recommendation regarding a potential path for improving the rate offering to the Commission by December 31, 2014. In July, the Company engaged Christensen Associates Energy Consulting (CA Energy Consulting) to assist in this effort.

The Settlement Agreement focuses on three objectives to guide the analysis and potential tariff revision:

- provide accurate and clear price signals to customers;
- help reduce North Dakota's contribution to the Company's peak periods; and
- minimize the incremental costs to administer the TOD rate.

Xcel Energy's TOD rate objective is to offer a rate that is "efficient", that is, a rate whose prices can be supported by the underlying marginal costs that are commensurate with the customers' unique energy usage patterns. The rate should be reasonably easy to administer and generally accessible to residential customers on a voluntary basis. The Company acknowledges that it would be useful for the resulting design to be a feasible platform for "dynamic" pricing programs like critical-peak pricing. As a result, a design that avoids having to make choices about dynamic pricing considerations would be desirable. If possible, an updated design would require limited modification as two-way (smart) metering technology becomes more prevalent.

Our conclusion, following extensive research into design alternatives, is that it would be difficult to find a cost-effective alternative to the existing residential TOD tariff that more effectively meets the Settlement objectives. Other designs with stronger pricing signals that could have a bigger impact on the way energy is consumed are available, but the current energy cost circumstances in North Dakota would not support such designs. Additionally, it appears that the technical changes needed to implement alternative designs (*i.e.*, metering and billing enhancements) are cost-prohibitive and would present challenges to the cost effectiveness of a redesign based on these alternatives.

### Project Approach

To identify potentially valuable or interesting design features that might be used in the redesign of the North Dakota rate, we began by investigating other utilities' residential TOD programs. We also obtained information on marginal costs and conducted statistical analysis to select

desirable pricing time periods for a redesigned rate. Additionally, we obtained information from Xcel Energy to review the utility's internal system capabilities and incremental costs of supporting modified rate structures and increased participation in TOD service. We then combined these three lines of research to determine what alternative TOD designs might be cost effective.

### Analysis of Existing Programs

A review of leading residential TOD programs currently offered in the United States revealed the following design tendencies:

- Two-period (peak and off-peak) designs predominate, although some programs include a “shoulder” period to create three-period designs.
- Two-season (typically summer and non-summer) designs are relatively frequent, as opposed to single- or three-season designs, as two-season designs are seen as sufficient to identify most utilities' peak energy cost season.
- The daily peak period usually consists of most daylight hours extending into the middle of the evening, on non-holiday weekdays.
- On-peak to off-peak price ratios, including fuel charges, are mostly in the range of 2:1 to 4:1, although there are exceptions.
- TOD rates that do not involve some form of demand response tend to be attractive to high load factor customers who are more likely to achieve savings relative to their standard tariff by having relatively more of their usage billed at the lower, off-peak rate.
- TOD rate designs with high participation appear to attract customers by some combination of lower rates (relative to the base (non-time-varying) residential tariff) and/or marketing inducements (*e.g.*, being provided a programmable thermostat).

The current TOD tariff in Xcel Energy's North Dakota service territory is aligned with common industry practice. The tariff is a two-season, two-period structure with the peak period consisting of the hours 9:00 am to 9:00 pm on non-holiday weekdays. The summer on-peak to off-peak price ratio of 3.2:1 is within the range of ratios found at other utilities and is sufficient, according to CA Energy Consulting's experience, to produce detectable customer price response in the form of load shifting out of the peak period. Xcel Energy's current price ratio is only slightly less than those found at relatively heavily subscribed programs, suggesting that increasing the price ratio on its own would not lead to significantly higher subscription rates.

### Marginal Costs and Optimal Time Periods

We utilized historical and forecasted hourly wholesale prices within the Midcontinent Independent System Operator's nodes that best reflect marginal energy costs in Xcel Energy's North Dakota service territory. We also obtained a representative residential class hourly load profile for the forecast period. We combined this information to create load-weighted averages of marginal cost for time periods selected by CA Energy Consulting's *PRIOPT* model. This model

locates pricing time periods for which the variance in marginal cost within time periods is minimized.

The model is used to guide the selection of optimal pricing periods given a TOD pricing structure (*e.g.*, two seasons, two time periods). The utility makes a subjective choice regarding pricing structure (*e.g.*, preferring two time periods to three, or three seasons to two) based on its rate design objectives. For example, a utility that has a strong preference for design simplicity might select a two-time period rate while a utility that makes pricing accuracy a priority might include a shoulder period in its design.

We calculated optimal time periods for three pricing structure options: 1) two seasons and two time periods; 2) three seasons and two time periods; and 3) three seasons and three time periods. The results appear in Tables ES.1–ES.3, below.

Increasing the number of seasons and time periods reduces marginal cost variance and permits identification of potentially meaningful marginal cost differences between time periods. As the tables below demonstrate, increasing the number of daily time periods increases the on-peak/off-peak marginal cost ratio. The summer ratio is 2.01:1 for a two-period approach, but increases to 2.36:1 for a three-period approach. However, both values are below the 3.2:1 ratio of the existing TOD rate. The three-period approach shortens the duration of the on-peak period, offering the customer greater convenience in shifting loads. On the other hand, the customer is dealing with a more complicated pricing structure. This added complexity can possibly be programmed into thermostats, but other customer end uses would face up to five pricing segments per day and a relatively modest marginal cost and, hence, price differential between periods.<sup>1</sup>

**Table ES.1**  
**Two Seasons, Two Periods per Season**

Season	Months	Hours		Marginal Costs \$/MWh		P/O Ratio
		On-Peak	Off-Peak	On-Peak	Off-Peak	
				[BEGIN TRADE SECRET]		
Summer	July-Aug	9am-10pm	10pm-9am			2.01
Non-Summer	other	7am-10pm	10pm-7am			1.57
				END TRADE SECRET]		

<sup>1</sup> For example, in Table ES-3, if Xcel Energy were to introduce three-period pricing in the winter season, the customer would have the following pricing segments: 7am-12pm (peak), 12pm-5pm (shoulder), 5pm-8pm (peak), 8pm-10pm (shoulder), and 10pm-7am (off-peak). The peak to off-peak price ratio would be just 1.73:1.

**Table ES.2**  
**Three Seasons, Two Periods per Season**

Season	Months	Hours		Marginal Costs \$/MWh		P/O Ratio
		On-Peak	Off-Peak	On-Peak	Off-Peak	
				[BEGIN TRADE SECRET]		
Summer	July-Aug	9am-10pm	10pm-9am			2.01
Winter	Dec-Feb	7am-9pm	9pm-7am			1.57
Shoulder	other	7am-11pm	11pm-7am			1.58
				END TRADE SECRET]		

**Table ES.3**  
**Three Seasons, Three Periods per Season**

Season	Months	Hours			Marginal Costs \$/MWh			P/O Ratio
		On-Peak	Shoulder	Off-Peak	On-Pk	Shldr	Off-Pk	
					[BEGIN TRADE SECRET]			
Summer	July-Aug	11a-6p	9a-11a/6p-11p	11pm-9am				2.36
Winter	Dec-Feb	7a-12p/5p-8p	12p-5p/8p-10p	10pm-7am				1.73
Shoulder	Other	9a-4p	7a-9a/4p-12a	12am-7am				1.78
					END TRADE SECRET]			

Incremental Program Costs

Xcel Energy can readily handle the addition of customers to a two-period TOD program. Using current metering technology, the incremental cost of TOD service is about \$2.00 per customer per month. This is the current increment to the customer charge that the utility levies on TOD customers. A three-season, two-period structure would have similar incremental costs.

Three-period pricing structures would impose significant incremental metering, communication, and billing system costs of about \$250,000. Based on plausible TOD rate participation, the incremental cost over that of the two-period TOD tariff structure might be about \$2.00 per customer-month.

Cost-Effective Alternative Designs

Xcel Energy would deem a redesigned residential TOD rate cost effective if it could offer clear pricing that reflects the utility’s costs, benefit the Company and its customers in North Dakota by reducing peak demand, and avoid new charges that customers would not willingly accept in deciding to participate.

The research evidence indicates that such a rate structure is difficult to devise for Xcel Energy’s North Dakota service territory. The investigation of marginal costs demonstrates that,

regardless of the choice of price structure, the marginal cost ratio between peak and off-peak periods is likely to be lower in the future than the current TOD program's price ratio.

Conversion from costs to prices that adequately recover revenue requirements can occur in several ways, but increasing the price ratio relative to the forecasted marginal cost ratio would result in peak period prices far above marginal cost, challenging the objective of providing accurate and clear price signals. Also, it is questionable whether distortion of the marginal cost ratio is a desirable design feature.

The review of other TOD programs indicates that some programs make use of three-period pricing, which would facilitate greater pricing accuracy and a somewhat higher price ratio between the daily on-peak and off-peak periods. However, product price complexity and the somewhat higher incremental costs of this design might deter customer participation and frustrate the objective of attracting customers capable of shifting load to off-peak hours.

Additionally, it appears that achieving significant participation under a revised TOD rate would require overall reductions in energy bills or added value in some other way for customers, such as the provision of extra support services or load management equipment. This "revenue neutrality" issue is familiar to TOD rate designers. The concern over maintaining "revenue neutrality" can be alleviated in a couple of ways. First, since TOD customers can provide benefits to other customers via load shifting, it is reasonable to consider reducing or eliminating incremental customer charges for TOD customers. Many TOD programs adopt this strategy. Second, TOD customers tend to have above average load factors since a greater share of their load occurs during the lower-cost off-peak period. In consequence, TOD customers may be less costly to serve than the average residential customer. However, the extent of the price reduction necessary to attract customers may result in lower revenues than the commensurate cost savings (which are not easily measured), resulting in subsidized service.

In summary, while Xcel Energy could redesign its residential TOD tariff, modestly altering its peak periods and perhaps increasing the number of seasons and pricing periods, forecasted marginal cost ratios do not support a price structure that increases the on-peak/off-peak ratio relative to the current rate structure. This limitation would render the likelihood of increased load shifting small. Also, it is a matter of policy discretion whether a utility should reduce its overall TOD pricing or eliminate its customer charge premium. It appears unlikely that the load shifting benefits (demand-related cost savings) of increasing the number of residential TOD customers would exceed the incremental program costs or the resulting revenue attrition. Such attrition would need to be recovered by the utility via offsetting rate increases at some point. The potential outcome of a residential TOD rate redesign that would acquire new customers might well be the attainment of load shifting goals at the price of cross-subsidization by other residential customers.

## 1. INTRODUCTION

An ongoing priority of electric utility ratemaking, and of the regulators who review rate design, is efficient pricing. The Bonbright criteria for effective ratemaking include efficient pricing alongside familiar criteria such as revenue sufficiency and stability. Because wholesale prices vary systematically with time due to the inability to cost-effectively store electricity, utilities have attempted to use time-varying pricing to satisfy the efficient pricing criterion and to generate benefits for their customers and themselves.<sup>2</sup>

In theory, customers benefit from reduced bills by shifting consumption to low-priced time periods, and utilities (and their shareholders and customers) benefit from reduced capital costs that result from that load shifting. While many utilities have offered time-of-day (TOD) pricing to large customers, most until relatively recently have not successfully offered TOD service to small customers. Historically, the metering costs of TOD pricing have negated many of the potential benefits from mass market TOD service, and participation in residential TOD service has often been small.

Xcel Energy's experience in its North Dakota service territory fits this pattern. The Company has a residential TOD rate in its tariff book, but the tariff is poorly subscribed at present. Recognizing the increasing use of TOD options nationwide and the implementation of technology improvements for metering and billing systems, the North Dakota Public Service Commission (NDPSC) Staff determined that it would be timely to investigate the potential for updated residential TOD service in Xcel Energy's North Dakota service territory. The motivations and objectives of the NDPSC are made clear in the text below from the rate case Settlement Agreement approved in early 2014.

*The Parties agree to investigate the feasibility of redesigning the Company's TOD rate in a manner that will provide accurate and clear pricing signals to customers, help reduce North Dakota's contribution to the Company's peak periods, and minimize the incremental costs to administrate the TOD rate. By December 31, 2014, the Company commits to submitting to the Commission either a pilot TOD tariff or a recommendation regarding an appropriate path for improving a residential TOD offering in North Dakota.*<sup>3</sup>

The key elements in the above text are: 1) accurate and clear price signals; 2) reduction in North Dakota's contribution to Xcel Energy's peak periods (presumably by attracting significant numbers of new TOD customers whose load shifting will potentially reduce peak demand); and 3) minimizing the incremental costs of TOD program support.

Xcel Energy engaged the expertise of Christensen Associates Energy Consulting, LLC (CA Energy Consulting) to investigate the merits of a residential TOD rate update. The key elements of this

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<sup>2</sup> See Bonbright, J.C., A.I. Danielson, and D.R. Kamerschen, *Principles of Public Utility Rates*, c. 1988, Public Utility Reports, Inc., pp. 382-4. See attributes 4, 5, and 8.

<sup>3</sup> North Dakota Public Service Commission, *Revised Second Amended Comprehensive Settlement Agreement*, Docket Number PU-12-813, among others, Feb. 25, 2014, Sec. IV.D., p. 27.

investigation were deemed to be: 1) estimating the wholesale costs of appropriate time periods as a basis for clear price signals, and 2) a review of likely incremental costs associated with various candidate rate structures. Additionally, an investigation of residential TOD designs currently in the marketplace was considered vital to an understanding of possible rate structures and features. This report presents the results of this investigation.

Xcel Energy's rate objective is to offer a cost-effective TOD rate that is generally accessible to residential customers on a voluntary basis. The utility also considers that it might be useful if the resulting design were to be a feasible platform for "dynamic" pricing programs like critical-peak pricing. As a result, it may be best to avoid complex program changes that could limit future design considerations as two-way (smart) metering technology becomes more prevalent.

The report begins with a brief review of the TOD pricing concept and then offers the results of our investigation of current residential TOD designs. The following section reviews the marginal costs that Xcel Energy is likely to face in designing TOD service. The research on marginal cost provides a basis for the selection of desirable TOD pricing periods, a result of which is a forecast of likely peak period to off-peak period marginal cost ratios.

The report concludes with a qualitative evaluation of the potential for a cost effective update of residential TOD service at Xcel Energy in North Dakota.

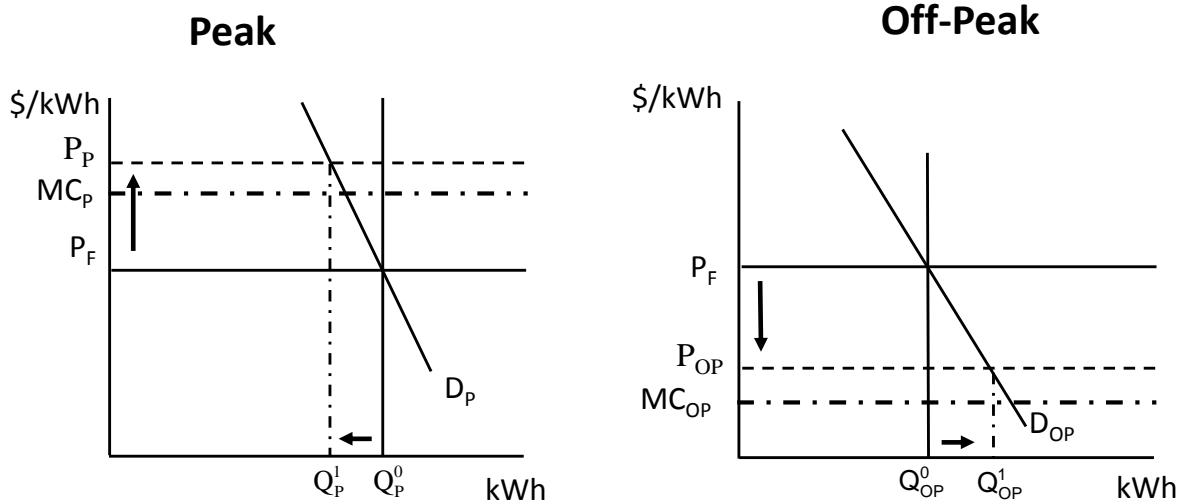
## 2. BENEFITS OF TOD PRICING

The purpose and benefits of TOD pricing can be seen in Figure 2.1, below. The figure depicts typical conditions at an electric utility in which the marginal cost of providing the next unit of consumption varies with time—high in the peak period and low in the off-peak period—but the residential retail price does not. This is common in flat pricing, block pricing, and within each day under seasonal pricing. The figure shows a flat price,  $P_F$ , in each period, below the marginal cost in the peak period,  $MC_p$  and above the marginal cost in the off-peak period,  $MC_{op}$ . Under a flat rate, the marginal cost of service is above the flat rate for incremental sales during peak hours and below the flat rate for incremental sales during off-peak hours.

In each period, assuming price sensitivity, the customer chooses to consume an amount of electricity determined by their demand for electricity. This demand is commonly depicted as being downward-sloping to the right, reflecting increased willingness to pay for electricity as the price declines. In the figure, under the flat rate, the customer consumes  $Q_p^0$  in the peak period and  $Q_{op}^0$  in the off-peak period.

If the utility elects to improve price efficiency by offering a TOD rate, which moves retail price closer to marginal cost—at  $P_p$  and  $P_{op}$  in the peak and off-peak periods respectively—then the customer with the depicted demand curve will reduce peak period usage and increase off-peak period usage. The customer in the figure now consumes  $Q_p^1$  in the peak period and  $Q_{op}^1$  in the off-peak period. (Prices exceed marginal cost to allow for a sales margin on incremental generation/supply services. In practice, charges for transmission and distribution service are added to energy prices.)

**Figure 2.1**  
**Load Shifting Under TOD Service**



The customer who modifies usage as shown benefits by definition because the customer will only change consumption if their change in value derived from the shift is greater than (or less negative than) the change in the bill. The simplest illustration of this fact is the case in which total usage does not change but the bill declines. However, a more general treatment relies on the idea that a customer will neither add to nor subtract from current usage unless they deem it worthwhile according to their own sense of value. (This value is captured by the demand curve.)

The utility benefits as well from such a shift, as the (marginal) cost of serving the peak period declines and the cost of serving the off-peak period increases, but by less per kWh. Importantly, the utility's need for capacity is reduced, and the need for future capacity increase is delayed, reducing the costs that need to be passed on to all customers. Thus the residential customer who shifts load out of the peak period delivers benefits to other utility customers by reducing the utility's cost of service.

One challenge to the cost effectiveness of residential TOD pricing has generally been that the cost of offering TOD service—metering, billing, and communication—has been large enough to negate the benefits of TOD service for many possible participants. Additionally, utilities face the well-known cost of offering customers product choice: revenue attrition. Customers who can choose between rates will choose the rate that will be likely to deliver lower bills, barring complicating rate provisions that might deter conversion to the new rate.<sup>4</sup>

Thus, a new or updated TOD product will face a deterrent if incremental costs are imposed on participants and if their perception of bill impacts may be unfavorable. *Status quo* bias will result in a customer having a less than 50 percent probability of converting to TOD service if the

<sup>4</sup> Another challenge is that while conventional TOD pricing recognizes cost differences within days, it does not directly recognize day-to-day cost differences that are often higher. "Dynamic" TOD products like critical-peak pricing attempt to meet this challenge for hours of extremely high cost.

expected bill impact of the conversion is zero. The result is that those who convert to TOD service expect to save money even in the absence of load shifting.

Managing this revenue attrition challenge has proven difficult for utilities. They face the issue of forecasting the revenue attrition and trying to find acceptable ways of recovering it through increased rates. One plan is to strive for TOD participant revenue neutrality by increasing TOD prices, but this invariably reduces the customer benefits of TOD service and, therefore, participation. The outcome is to restrict TOD service to customers who expect the largest bill savings in the absence of response and to the most price responsive customers in the rate class. Many residential TOD programs have very low participation as a result.

The alternative is to “socialize” the attrition by increasing rates to other customers. Unless TOD rate subscribers prove to be less costly to serve than customers who remain on the standard tariff, the outcome is cross subsidization. Rationales for this approach are: 1) that TOD customers provide benefits to other customer through shifting away from peak periods and 2) that those who convert to TOD service may well have lower costs to serve, as evidenced by their willingness to move. (Immediate savings from the move are relatively higher for customers with lower shares of load in the peak period.)

In summary, the pricing options of a utility contemplating TOD service are a combination of: 1) the definition of pricing periods; 2) the relative prices among these periods; and 3) the overall level of TOD average price per kWh relative to the utility’s base tariff, including the size of incremental customer charges.

Xcel Energy’s pricing approach under the existing Residential Time of Day Service program, is to set energy prices for two seasons and for two time periods with the average TOD rate equivalent to the flat energy rate. The timing of the peak period does not vary by season, and consists of the hours 9:00 am to 9:00 pm on non-holiday weekdays. All other hours are off-peak and there is no “shoulder” period in which prices would be set at a level between the peak and off-peak levels. Table 2.1 summarizes the energy prices of the existing rate.

**Table 2.1<sup>5</sup>**  
**Xcel Energy’s North Dakota Residential TOD Energy Prices per kWh**

<b>Time Period</b>	<b>Season</b>	<b>Standard</b>	<b>Space Heating</b>
On-Peak	June-September	14.292¢	14.292¢
On-Peak	Other months	10.281¢	8.838¢
Off-Peak	All months	2.380¢	2.380¢

Other rate provisions include a customer charge of \$16.00 per customer-month, \$2.00 per customer-month more than the standard tariff, and a monthly fuel cost rider of approximately 3¢/kWh, the same price as for all other residential customers. Adding this fuel value to those in the table results in a summer on-peak to off-peak price ratio of about 3.2:1, and a non-summer ratio of about 2.4:1.

<sup>5</sup> Xcel Energy Electric Rate Book, Tariff Sheet 5-2; Rates are effective May 1, 2014.

Xcel Energy offers a limited number of customers (up to 100) an optional trial period of three months, with a customer who elects to return to the base tariff paying \$20 to defray the cost of meter conversion.

### **3. REVIEW OF REPRESENTATIVE TOD PROGRAMS**

This section of the report summarizes the results of an investigation of illustrative residential TOD rates of potential interest to Xcel Energy. CA Energy Consulting identified a number of rates based on background knowledge of current TOD rate designs, and supplemented this list with a number of rate programs familiar to Xcel Energy and NDPSC Staff. The review is not intended to provide a comprehensive perspective on the state of TOD rates nationwide, but rather to present design structures and pricing patterns that indicate the variety of TOD programs in the market. The list of utility residential TOD programs examined appears in Figure 3.1.

The investigation results are presented in the following four sub-sections. The first reviews the various TOD structures, focusing on the number and variety of pricing periods, and mentioning other tariff features that might merit consideration. The second sub-section describes the pricing elements of the TOD tariffs, primarily the price ratio between the most expensive peak pricing period and the least expensive within the peak season. This on-peak to off-peak price ratio is the key element in consumers' tendency to shift usage to lower priced periods, a key source of benefit from TOD pricing. Another pricing feature is the degree to which rate designers attempt to achieve revenue neutrality relative to an underlying rate.

The third sub-section summarizes the characteristics of specific selected tariffs of particular interest. A summary in the fourth sub-section draws inferences from the review for use in Xcel Energy's own redesign efforts.

#### **3.1 Residential TOD Structure**

##### **3.1.1 Pricing Periods**

A central element of TOD rate structure is the pattern of pricing periods. The tariffs reviewed for this analysis indicate that two-period structures (an on-peak and off-peak period) are more prevalent than three-period structures (containing an additional shoulder period). Of twenty tariffs, just five include a shoulder period. These five are not all geographically similar, although three are in the upper Midwest: Gulf Power is located in Florida, Nevada Energy North in the far West, and MidAmerican Energy, WE Energies, and Wisconsin Public Service are located in the upper Midwest. Accordingly, the use of shoulder periods does not appear to be strongly related to geography, which might otherwise reflect factors such as regulatory preference or underlying wholesale market circumstances.

As noted previously, Xcel Energy's North Dakota Residential Time of Day Service is a two-season, two-period design, conforming to the most popular design among the tariffs reviewed.

Figure 3.1, on the next page, depicts the range of pricing periods utilized by the utilities investigated. Xcel Energy's North Dakota pricing periods appear at the bottom of the figure for reference. The utilities reviewed are arranged alphabetically with the exception of three competitive market providers who are segregated at the bottom of the figure. Summer peak periods are identified in red, while winter or non-summer peaks are dark blue. Shoulder periods are yellow in summer and light blue elsewhere. A green bar across all 24 hours identifies periods of non-time-dependent pricing. The hours are labelled according to military time, hours 1 through 24, with the result that a peak period from 9:00 am to 9:00 pm includes hours ending 10 through 21. Dashed lines divide the day into four six-hour blocks.

In most cases time-varying pricing applies to non-holiday weekdays. Holidays and weekends are usually treated as off-peak. However, there are a few exceptions. Interstate Power (Iowa) and Montana-Dakota Utilities appear to treat holidays as identical to weekdays, rather than classifying them as weekend days. Nevada Energy North treats non-summer weekends and holidays as identical to weekdays, that is, maintaining TOD pricing but not distinguishing between day types.

All utilities but one—Salt River Project—divide the year into two seasons, with SRP employing three. (Note the light shading of the “summer” period of May, June, September, and October, and the full shading of “summer peak” of July and August.) Utilities in northern locations tend to have short summer seasons of three to four months, while those in warmer locations have longer summer seasons. Both Arizona Power and Gulf Power have six-month summers from May to October.<sup>6</sup> Two utilities—Georgia Power and Oklahoma Gas & Electric—simplify their non-summer seasons by using energy pricing that lacks time differentiation, confining the complexity of TOD service to the summer season.

Salt River Project offers two TOD products, one experimental (E-21/22/25) and the other (E-26) as their regular TOD tariff. As the figure shows, the experimental E-25 rate features a narrow three-hour peak period and restricts all seasons to the same peak time period. (Companion Tariffs E-21 and 22 offer the same pricing as E-25, but with slightly different three-hour windows. The arrows indicate the range of the peak period of the combined offerings.) In contrast, E-26 has a seven-hour summer peak and a non-summer split peak covering 5:00 am to 9:00 am and 5:00 pm to 9:00 pm. The experimental rate features higher prices in both periods, but with significantly higher on-peak prices.

WE Energies offers its Wisconsin customers two TOD tariffs. One tariff provides a constant twelve-hour peak period year-round, but also includes choice as to when the peak period starts, at 7:00, 8:00, 9:00, or 10:00 am, as signified by the arrows that indicate the boundaries of the four time periods. The second tariff features varying peak periods across seasons and includes a shoulder period as well.

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<sup>6</sup> Most tariffs describe their seasons in terms of billing months and thus do not prorate usage based on calendar months.

Figure 3.1

Peak Periods, by Season

Utility/Provider	Season	Hour of Day (hour ending)																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Arizona Public Service	May-Oct	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Nov-Apr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Duke Energy North Carolina	Jun-Sep	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Georgia Power	Jun-Sep	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Gulf Power	May-Oct	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Nov-Apr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Iowa Interstate Power	Jun 16-Sep 15	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Sep 16-Jun 15	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
MidAmerican Energy	June-Sept	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Minnesota Power	All	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Montana-Dakota Utilities-North Dakota	Jun-Sep	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Nevada Energy - North	Jul-Sep	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-Jun all days	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Oklahoma G&E	Jun-Oct	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Nov-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Salt River Project - E21, E22, E25 Experimental Super-Peak	May, Jun, Sep, Oct	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Jul, Aug	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Nov-Apr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Salt River Project - E26	May, Jun, Sep, Oct	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Jul, Aug	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Nov-Apr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
San Diego G&E	May-Oct	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Southern California Edison	Jun-Sep	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WE Energies WI RG2	All	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WE Energies WI RG3	Jun-Sep	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Wisconsin Power & Light	Jun-Sep	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Wisconsin Public Service	May-Sep	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-Apr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Consolidated Edison of NY	Jun-Sep	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PenElec	All	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TXU	All	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Xcel ND	Jun-Sep	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Oct-May	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

	Peak	Shoulder	All-Hours
Summer			
Non-Summer			
Shoulder			

The majority of utilities offer TOD pricing year-round, but change either the time period definition or the pricing or both with the change of season. Twelve utilities constrain their pricing periods to be identical or quite similar across seasons. The two California utilities illustrate this strategy, with the peak period being 10:00 am to 6:00 pm for Southern California

Edison and noon to 6:00 pm for SDG&E all year. For some utilities with shoulder periods, the timing of the shoulder period can change between seasons, but the combined shoulder and peak periods are identical in duration across seasons. Wisconsin Public Service is an example of this approach, while MidAmerican Energy provides exact uniformity of pricing periods.

Xcel Energy North Dakota adopts the strategy of having a single peak period year-round, twelve hours from 9:00 am to 9:00 pm. Peak prices differ across seasons, but the off-peak price is uniform.

Utilities that employ shoulder periods have shorter length peak periods. Summer and non-summer peak periods for these four utilities are just four to six hours in length while eight to twelve-hour peak periods are common for utilities with two pricing periods per season. However, two-period utilities do not necessarily have long peak periods. Georgia Power's and Oklahoma G&E's summer peaks are just five hours in duration, from 2:00 pm to 7:00 pm, and San Diego Gas & Electric's peak periods are just six hours long.

Two utilities provide examples of non-summer peak periods that include early morning hours. Salt River Project's E-26 rate features a split peak, with four hours in the morning and four in the evening. Duke Energy North Carolina's non-summer peak runs from 7:00 am to noon.

The three utilities that operate in customer choice circumstances all have pricing periods that are fixed for the year. Two of these—Consolidated Edison and Pennsylvania Electric (Penelec)—offer TOD service as part of their service to customers who remain with them. TXU, on the other hand, is a retail electric provider (REP) in the active ERCOT (Texas) market, offering service in several transmission and distribution utility (TDU) service territories. TXU provides perhaps the most unusual TOD product of all those reviewed. The pricing of their “Energy Free Nights 18” offering is discussed below. For the present, it is sufficient to note that their peak pricing period is quite long and does not vary by season.

Lastly, the table distinguishes between utilities that have unchanging pricing periods but separately identified seasons and those denominated as “all” in the season column. The latter group has similar pricing across seasons, while the former have different pricing for each season.

There is discretion in determining whether each pricing period should have its own price or, alternatively, whether a single price should be used for more than one period. Combining prices is particularly attractive for off-peak periods. In devising pricing periods, the utility confronts a trade-off between product complexity—the fewer the number of periods, the simpler the rate—and price accuracy, as measured by the proximity of retail price to marginal cost.

The tariffs reviewed in this study mostly do not combine pricing periods beyond making the off-peak weekday price identical to the weekend price in the same season, in brief, creating a single off-peak period for the season.

## Summary

The tariffs examined above offer no clear pattern for pricing periods or seasons, customizing designs to their preferences and cost patterns. Based on the programs examined, most utilities stick to two pricing seasons and two pricing periods per season, but the three-period season is also well established where used. In consequence, there appears to be broad discretion in determining how to structure pricing periods for the Xcel Energy TOD program in North Dakota.

### 3.1.2 Other Structural Features

#### Pilot vs. Permanent Status

Aside from selection of pricing periods and actual prices, the residential TOD rates reviewed here display some variety in other product features. One of these is rate status in the tariff book: permanent tariff vs. pilot program. For the most part, these rates are permanent tariffs, and in all cases options that give customers an alternative to a standard tariff that is either flat or seasonal.

One exception is the Salt River experiment described above, in which the peak period is narrowed, and the on-peak to off-peak price ratio is increased relative to their permanent TOD rate. The experiment also includes a requirement that the customer have access to smart meter communications.

A second pilot TOD program is Minnesota Power's Pilot Rider for Residential Time-of-Day Service. This pilot is described immediately below in the sub-section on default tariff characteristics.

Another exception to the rates discussed above, although not experimental, is Arizona Public Service's ECT-2 tariff, which offers TOD service on the same time pattern as the rate reported in the table (ET-2), but with a demand charge that varies by season, applicable to on-peak period peak demand. This is one of only two examples from programs investigated where demand charges were introduced to residential TOD customers. The other is Duke Energy North Carolina, which used a seasonally varying on-peak demand charge.

#### Default Tariff Characteristics

A second structural feature involves the default residential tariff. This is only of interest if the default tariff presents problems for a TOD offering. A blocked tariff is notable in this regard. A TOD tariff offered to residential customers on an inclining block tariff will attract predominantly large customers, since they will be more likely to experience immediate bill savings by transferring to TOD service than will small customers. Since Xcel Energy's North Dakota residential tariff does not involve blocking, this issue does not arise.

Interestingly, TOD service can be combined with a blocked tariff by creating a rider that provides a price premium in peak hours and a discount in off-peak hours. Under this structure, the rider produces savings or a bill increase based on the customer's peak period coincidence. Minnesota Power has such a rider.

Xcel Energy's North Dakota default tariff is a seasonal rate with pricing segmented by customer type. Both standard and space heating customers have the same energy charge in summer but,

in winter, space heating customers, who use relatively more energy off-peak than standard customers, have a lower energy price than that paid by standard customers.

Such a structure may influence the TOD design choices of the Company. First, cold winters and the resulting concentration of electric space heating and in North Dakota suggest that defining a third, winter season might improve pricing accuracy. Second, a TOD offering may eliminate the need for special pricing of space heating under TOD service, since differences in the time pattern of consumption, and hence cost to serve potentially could be captured in pricing by time period, provided that the time periods adequately reflect the time pattern of marginal cost. Since the winter and summer time patterns in this service territory are quite different, this suggests that each season have its own peak period definition, rather than trying to impose a single pricing period on both summer and winter seasons.

#### Length of Contract/Service Commitment

TOD service usually has a commitment requirement in some form to deter seasonal “rate hopping” between the TOD tariff and the default tariff (or other offerings). Most utilities require that TOD participants commit to the tariff for a year. Xcel Energy uses this approach.

An alternative approach involves allowing the customer to leave with thirty days’ notice, but to forbid reapplying for TOD service for a period of one year. Salt River Project adopts this approach.

Gulf Power’s offering is more lenient in this regard, requiring just thirty days’ notice and apparently not imposing further restrictions. Wisconsin Public Service requires just a three-month commitment. However, these examples are exceptions to the annual commitment standard.<sup>7</sup>

#### Risk Protection for New TOD Customers

One way in which utilities reduce the risk of the one-year commitment requirement is to offer customers a bill protection clause. For example, Oklahoma G&E has a “best bill” provision in its tariff that charges customers the lesser of the TOD and standard residential tariff during the first year of service. Thereafter, the customer must choose a tariff and abide by its bill. Incidentally, OG&E also provides a senior citizen discount of \$5 for each summer season bill to attract otherwise conservative customers. Nevada Energy North also offers a best bill provision.

WE Energies has in the past used two other techniques to reduce risk and attract customers. First, they offer customers a choice of twelve-hour peak period, beginning at 7, 8, 9, or 10 am, which allows customers to select a tariff tailored to their lifestyle. This provision has the added attraction of staggering load shifting behavior and reducing the risk of creating a new peak just outside the peak period of the tariff. Second, the utility has offered customers three levels of TOD pricing with differing price ratios. The low Level 1 price ratio is advertised as a low-risk training tariff, while Levels 2 and 3 increase savings from load shifting but increase risk of exposure to high prices. Level 3 is a three-period seasonal TOD structure while the other levels

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<sup>7</sup> The SCE TOD tariff appears to make no mention of departure limitations. This may reflect the presence of a re-emerging customer choice market or departure rules may be recorded in text not part of the tariff.

are two-period year-round structures. Level 3 features a short peak period with very high prices.

Xcel Energy North Dakota currently uses a straightforward mechanism that provides customers with a three-month trial period. This approach is slightly more limited than that of other utilities in that customers may not experience a peak season or a season of higher bills than previously by the end of the trial period simply because of when they chose to begin their trial period.

#### Compatibility with Demand Response

Few of the rates reviewed here offer dynamic pricing or demand response features directly. However, several utilities do offer such rates in addition to their “static” TOD rates. (A static rate features prices in tariff sheets that change only with rate cases or with changes in rider or tracker values. A dynamic rate features some form of short-notice condition announcement, even if the price that applies in such conditions is posted well in advance. A critical-peak pricing (CPP) rate, in which critical-peak periods are announced with short notice but the CPP price is posted in a tariff, is a good example of a dynamic pricing rate.)

Minnesota Power’s pilot tariff and Gulf Power’s RSVP rate have CPP pricing periods. A CPP rate that has an underlying TOD structure typically has reduced regular TOD prices relative to a static TOD tariff and a maximum number of hours in a year in which a high CPP price can be charged.<sup>8</sup> The presence of these two rate examples indicates that a utility can, if it wishes, make its basic TOD rate dynamic, and can presumably convert a static TOD rate to a dynamic rate at any future date without revising the tariff structure completely. However, such a conversion would also require that the utility develop or already possess the necessary technical capabilities to support such a design. Assuming technical cost effectiveness, pre-existing TOD pricing periods can be retained and prices revised downward to compensate for anticipated enhanced revenue recovery during CPP hours and reduced cost to serve because customers tend to avoid high-cost hours.

Arizona Public Service and Southern California Edison offer a variant of CPP called peak-time rebate (PTR) service. PTR is similar to CPP in offering very high pricing at short notice for critical peak periods. However, in those periods, PTR charges the customer the peak period TOD price for a contractual amount of usage (usually estimated by the utility, based on past peak period usage) and then charges (rebates) customers at a critical-peak rate for increases (decreases) from that contractual level. This product is more complicated than CPP in its use of a contractual “customer baseline load” (CBL) and simpler in that it does not require an alteration in the standard TOD pricing, since there is no expected change in revenue recovery. Administration of this type of design would also be complex.

#### Compatibility with Electric Vehicle Pricing

Similarly, the static TOD rates reviewed here do not typically make explicit mention of electric vehicle (EV) charging support. However, there are exceptions. Gulf Power’s RSVP rate title mentions EV charging but there is no text in the tariff specific to this service. Both California

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<sup>8</sup> A CPP rate can also be based on an existing flat rate, which may increase accessibility for some customers.

utilities offer EV charging in stand-alone tariffs. In this case the utilities elected to create separate tariffs, presumably indicating that EV service is provided through a separate meter. The complexity of San Diego G&E's blocked tariffs might have induced this approach.

Other utilities with TOD designs do not yet have EV tariffs and do not appear to have text requiring that EV service be via TOD rates. EV loads appear to invite TOD pricing since an off-peak price materially below a flat price will significantly increase the attractiveness of an EV rate. Whether the admission of EV service to a standard TOD rate would affect the selection of pricing periods and levels may need further investigation. For example, if off-peak prices do not differ by season, the profitability of serving EV loads might be needlessly seasonal.

### Summary

The tariff elements described above can be seen as potentially influencing the attractiveness of a revised Xcel Energy TOD tariff from customers' and regulators' perspectives. There appears to be little benefit to offering a pilot program unless some significant component of the tariff is truly innovative and deserving of study. That does not appear to be the case for Xcel Energy in North Dakota, due to the absence of blocking and competitive alternatives.

Risk reduction in the form of a first-year minimum bill provision may be attractive, although this approach is certainly not widespread. The use of multiple time periods seems overly complex, perhaps of better use in expanding an established program in which load shifting might come to have implications for utility conditions. The potential for this outcome in North Dakota seems small. Lastly, while the key to attracting customers is likely to be the overall cost of TOD service to the customer, the above features may merit consideration.

## 3.2 Pricing

TOD pricing has two dimensions of importance. The first pricing dimension is the on-peak to off-peak price ratio in each season. The peak season ratio especially provides a handy summary of the potential for load shifting by customers who respond to the new price differential. A related element is the pricing of shoulder periods and the linking of prices across seasons and time periods. The second main dimension is the level of the TOD prices compared with those of the default tariff, as manifested by bill comparisons in the absence of price response. This comparison will be a leading factor in the customer's decision to participate in TOD service.

### 3.2.1 Price Levels and Price Ratios

The figures below summarize the energy prices charged by the various tariffs, including adjustments for major riders, especially fuel and purchased power. In cases in which the utility includes a demand charge, that value is converted to a price per kWh by dividing the price per kW by the number of hours in which the demand charge might be incurred.<sup>9</sup>

Figure 3.2 reveals a wide variety in summer peak period price levels. The highest prices exceed \$0.50/kWh, while most summer season peak period prices are in the range of \$0.15 to

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<sup>9</sup> This assumes that the customer sees each on-peak hour as being equally likely to set a new peak, a simplifying assumption.

\$0.50/kWh. Non-summer season peak period prices are lower, generally in the range of \$0.07 to \$0.25/kWh, as Figure 3.3 shows.

Figure 3.2

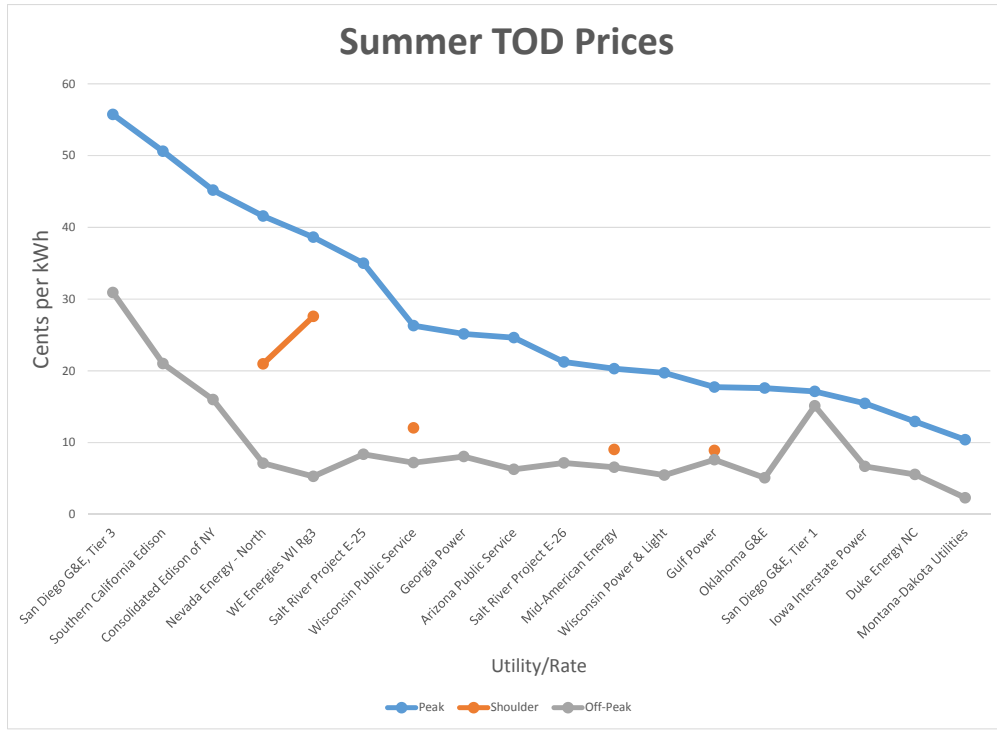
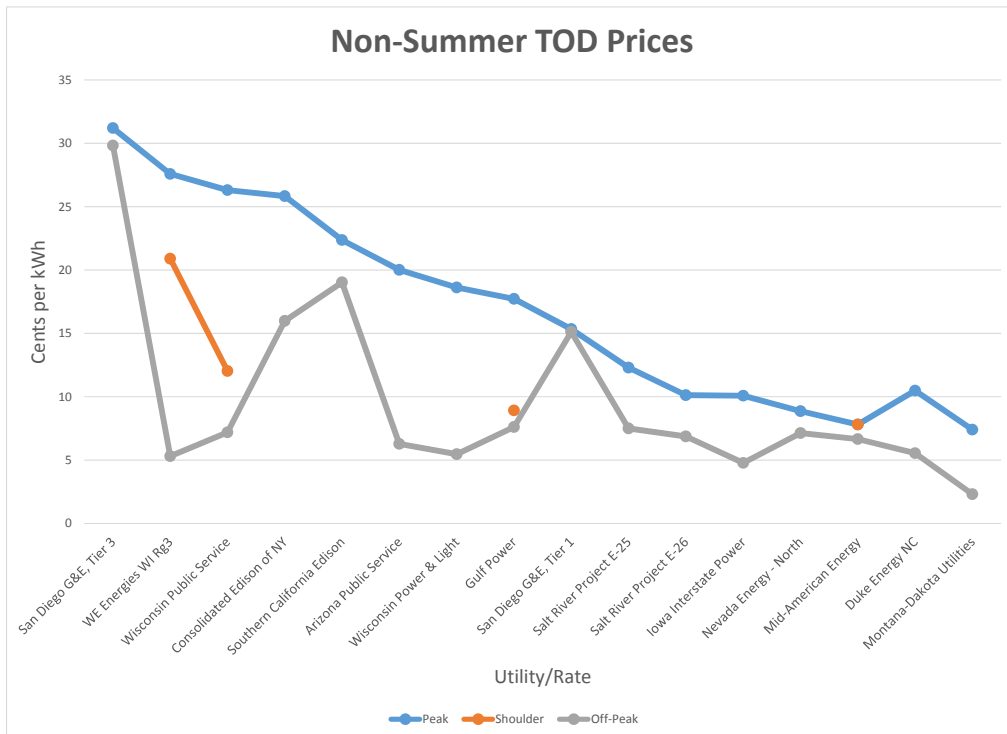


Figure 3.3



Xcel Energy's North Dakota summer peak period price, adjusting for fuel cost, is about \$0.174/kWh, and the off-peak price is about \$0.055/kWh.<sup>10</sup> Non-summer peak and off-peak prices are about \$0.134/kWh and \$0.055/kWh. The summer peak price is thus at the low end of the range of observed prices, but other prices are closer to the average.

Figures 3.2 and 3.3 both indicate that there is weak correlation between on-peak and off-peak prices, barring the very expensive California and New York City markets. Shoulder prices appear slightly positively correlated with peak prices, but there is too little information to draw a conclusion. The influence of the use of shoulder pricing is perhaps evident in the Nevada Energy North and WE Energies summer pricing, and in the WE Energies and Wisconsin Public Service non-summer cases, which show relatively low off-peak values compared to other values nearby in the figure. The figure does not support this supposition for the other three-period tariffs, though. (Note that one three-period tariff, Nevada Energy North's, is absent from the non-summer figure since the utility does not use three-period pricing in the non-summer season.)

The two figures above provide some detail on a couple of TOD designs. San Diego G&E has an inclining block TOD tariff that has a high on-peak price for Tier 3 but a relatively low price for Tier 1. As a result, the rate shows up in two fairly distant points in the figures. Similarly, Salt River Project's two tariffs appear far apart in the summer figure since the short peak period of the experimental tariff E-25 pushes up the price relative to E-26.

In some cases, the contrast between summer and non-summer peak period prices is quite significant. For example, MidAmerican Energy's summer peak price is 20.295 ¢/kWh while the non-summer peak value is just 7.809 ¢/kWh. The opposite extreme occurs when a utility produces an all-seasons TOD product, with a single peak price for the entire year. Tariffs with separate seasons appear in Figure 3.4 below. The figure indicates that summer and non-summer peak prices are weakly correlated. Perhaps this is to be expected given the variety of season lengths and climate differences across utilities.

The range and pattern of prices does not reveal underlying costs of the utilities or their methodologies for converting costs to prices. However, the revealed prices provide an indication of the distribution of prices currently found in the market. The price ratios resulting from these prices appear in Figure 3.5 below.

Summer price ratios are predominantly in the range of 2:1 to 4:1, although there are several in excess of the top of this range. Non-summer price ratios appear to be slightly lower, in the range of 1.5:1 to 3.5:1, with one above the range.

Xcel Energy's North Dakota service territory's price ratios are 3.2 during the peak summer season of June to September and 2.4 during the non-summer season. In both cases, these ratios are in the middle of the observed range.

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<sup>10</sup> The fuel charge used in these computations is the August 2014 rate of \$0.03089/kWh.

Figure 3.4

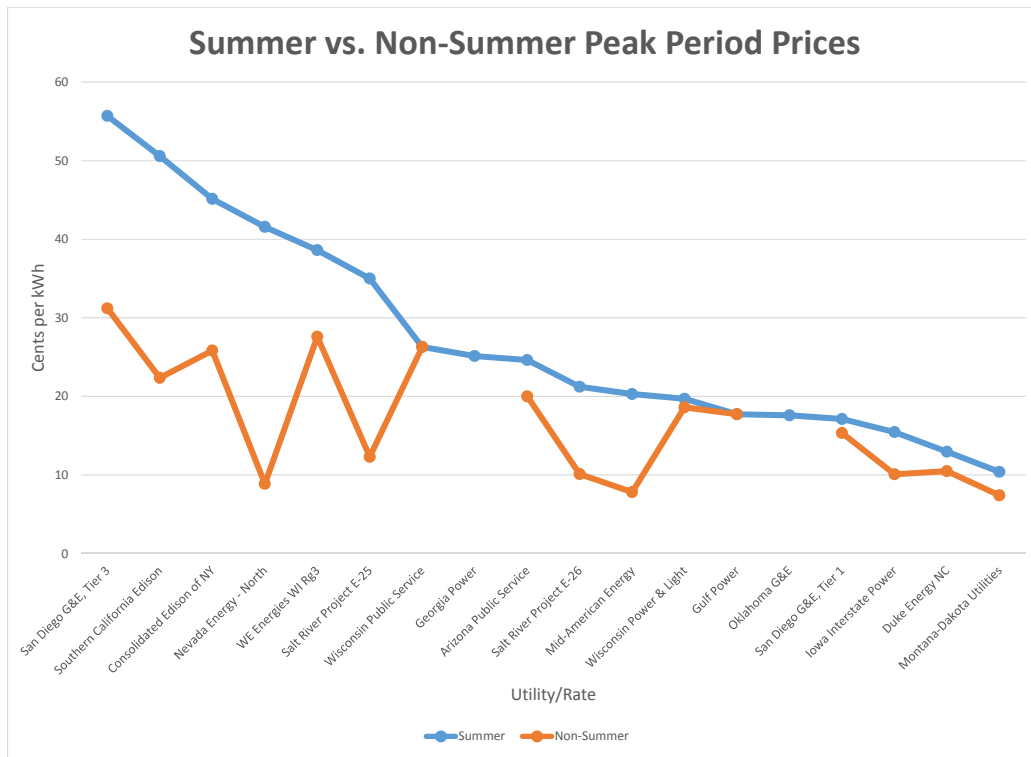
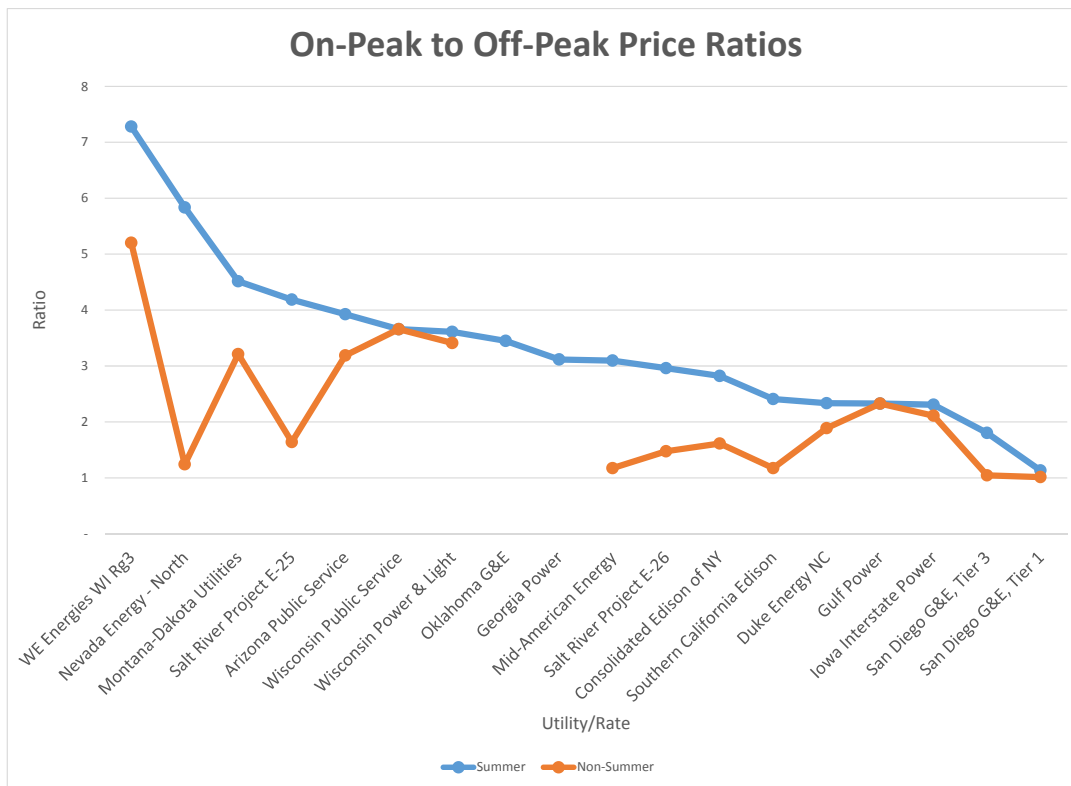
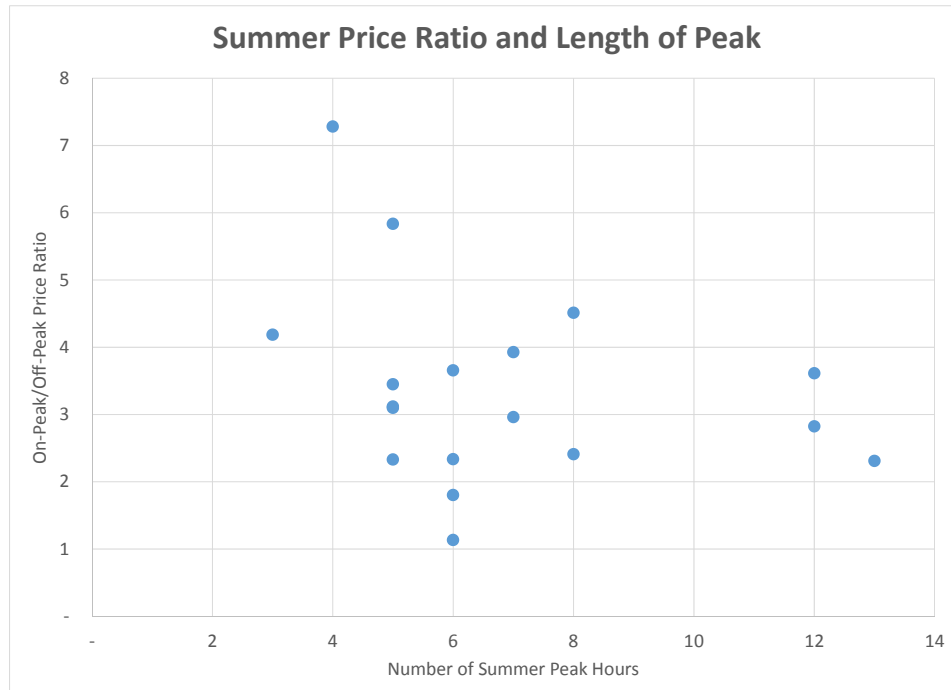


Figure 3.5



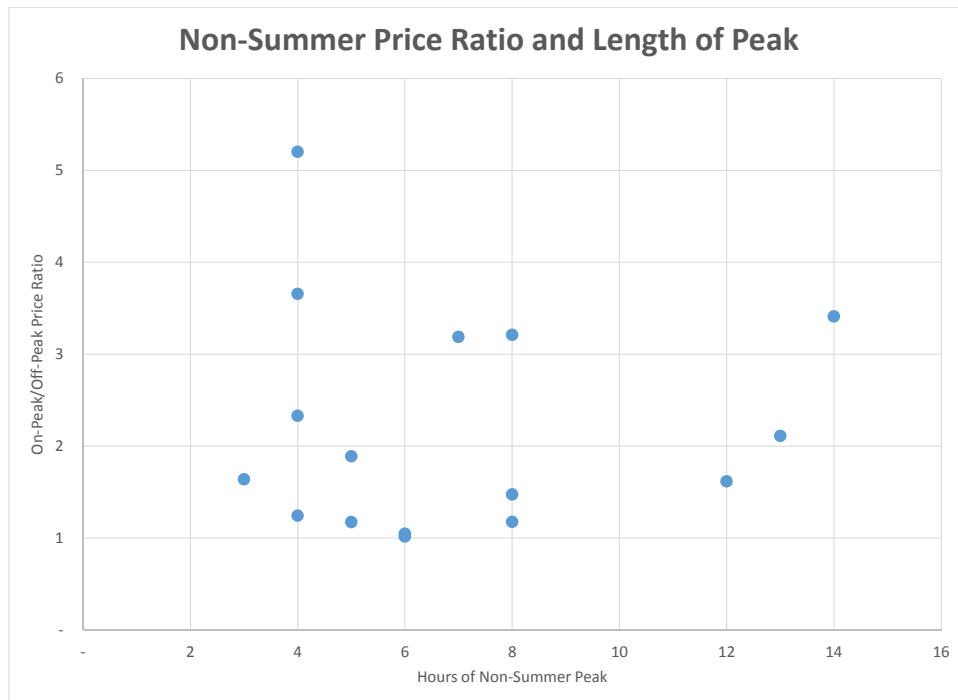
Another dimension of pricing relates to the length of the peak period. By selecting a short peak period, or adopting a three-period approach that typically features a relatively short peak period, one might expect to increase the on-peak to off-peak price ratio. Figures 3.6 and 3.7 below present the combinations of peak period duration and price ratios for summer and non-summer periods found in the tariffs under review. The summer period appears to display the anticipated negative correlation between peak period duration and price ratio. However, the non-summer figure does not replicate this pattern.

**Figure 3.6**



The utilities with summer peak ratios above 4:1 are: WE Energies (Rg3), Nevada Energy North, Montana-Dakota in North Dakota, and Salt River Project's experimental E-25 rate. Those with non-summer peak ratios above 3.5:1 are WE Energies (Rg3) and Wisconsin Public Service. Three all-season rates provided by WE Energies (Rg2) Penelec, and TXU also have high ratios. Thus, it appears that there is something of an upper Midwest concentration, given the presence of MDU-ND and the Wisconsin utilities. Note however, that Penelec and TXU are offering products in competitive retail markets, which may reduce their relevance to the regulated market in North Dakota.<sup>11</sup>

<sup>11</sup> One might argue that a regulated market should attempt to mimic the competitive market, where possible, and that rate experiments that increase customer choice could be encouraged.

**Figure 3.7**

Nevertheless, it is worthwhile to review the TXU product due to the innovative nature of its design. The “Energy Free Nights 18” product is an 18-month retail contract that offers energy at night (9:00 pm to 6:00 am) at zero cost. Not only is the energy provided by TXU free, the company rebates to customers the cost of the transmission and distribution utility (TDU) related to this nighttime usage, offsetting this rebate with a price increase in other hours. Thus, the price ratio for TXU is infinity, because the change in the customer’s bill from adding usage at night is zero, and this fact is perceived by the customer.

This is not the only product of this nature in the marketplace. TXU also offers a “free weekends” product<sup>12</sup>, and another Texas provider, Direct Energy, offers a 12-month contract including free energy on Saturdays.<sup>13</sup> These products have been heavily criticized in the media because of their high average prices. However, they would provide bill savings to customers who can consume relatively high shares of energy during hours when energy is free.

From an economic perspective, they appear to be difficult to defend due to the relatively inefficient pricing of energy when compared with wholesale prices. An energy provider actually experiences a cost increase and a revenue decrease when a customer increases usage in an hour in the free energy period. The provider pays the cost of the energy and also reimburses the TDU at their stated energy price. As compensation, the price to add consumption in other hours is, of necessity, farther above marginal cost than would be the case in the absence of free energy periods.

<sup>12</sup> <https://comparepower.com/txu-free-weekends-free-nights-unplugged-avoid-a-720-dollar-mistake/>

<sup>13</sup> <http://www.directenergy.com/texas/freepowerday>

### 3.2.2 Other Price Elements

Certain TOD tariffs include charges not found in most conventional designs. These include demand charges and incremental customer charges. Additionally, fuel charges are sometimes given a TOD configuration.

#### Demand Charges

Demand charges have not been used in mass market conditions due to metering limitations, but the spread of interval data recording has opened up this avenue to cost recovery. Introducing a demand charge into TOD may enable a utility to bring its energy charges closer to energy-related unit cost overall, and perhaps to marginal cost by time period, by placing fixed cost recovery into demand charges.

From the customer's perspective, though, a demand-related price is perceived as part of the cost of increasing consumption when that consumption is near its peak. Thus, the "effective energy charge" of the customer in peak periods may include the demand price, allocated to peak hours based on probability of setting a new peak. A simple construct is to average the demand price equally across all the peak hours in the billing period.

Consider Duke Energy North Carolina's RT rate, which includes demand charges as an example. The tariff features on-peak demand charges of \$7.77 per kW in summer and \$3.88 per kW in non-summer months. The energy price differentials in both seasons are relatively narrow, but if these demand prices are averaged across all peak hours, the result is a price ratio of about 2.3:1 in summer, and 1.9:1 in the non-summer season.

Arizona Public Service also offers a TOD product with a peak period demand charge, with summer and non-summer values of \$13.50 per kW and \$9.30 per kW. In APS's case the ECT-2 tariff that includes these charges is an alternative to the main TOD rate, ET-2. In Duke Energy's case, the main TOD tariff includes demand charges.

Another consideration with respect to demand charges is that they complicate rates and represent a novelty to residential customers. Whether customers will consider the new charge to be a deterrent to participation is something that APS and Duke Energy North Carolina will be testing.

#### Incremental Customer Charges

Another infrequent addition to TOD tariffs is an incremental customer charge. The purpose of this charge is to help to defray the incremental costs of TOD service, including metering, billing and customer support. Seven of the 20 tariffs reviewed in this sub-section have such increments. They range in value from about \$1.00 per month to about \$8.50 per month, or about \$12 to \$100 per year.

Xcel Energy's North Dakota residential TOD tariff employs an incremental customer charge, valued at \$2.00 per month. The customer charge is \$16.00 per month for TOD service compared to \$14.00 for the standard residential tariff.

The challenge in imposing such incremental charges is that they directly reduce the benefits to customers of participating in TOD service. Since TOD customers confer benefits on other customers by shifting load to lower cost time periods, consideration may need to be given to whether TOD rate subscribers should be required to pay all the incremental costs associated with administering the TOD service. Perhaps for this reason, in an effort to not deter participation, the majority of TOD service providers elect not to impose additional customer charges beyond those in the standard tariff.

#### TOD Fuel Charges

A third price element is the treatment of fuel charges. For utilities in which the bulk of fuel charges are embedded in base rates and only departures from forecast are recovered or disbursed via a fuel adjustment charge, this is not a significant issue. Utilities that place all fuel cost recovery in fuel charges must consider whether TOD rates should have TOD fuel costs. Typically, this involves estimating what fuel costs are incurred by pricing period and then dividing this cost by expected consumption during the period. While this can be done, it tends to produce rather narrow price differentials, since the basis for costing is embedded and not marginal cost. Additionally, the estimation and true-up process may add further layers of complexity with little added value.

Georgia Power and Oklahoma G&E both adopt this approach, with recent fuel price differentials by time period of about 1.4 and 1.2 ¢/kWh respectively. While TOD fuel pricing can be undertaken, TOD pricing typically has scope to set prices to recover expected costs but with price differentials between periods designed to reflect marginal cost differentials, regardless of fuel price differentials.

Xcel Energy's North Dakota fuel cost rider does not distinguish between peak and off-peak periods.

#### 3.2.3 Illustrative Bill Comparisons

The foregoing structure and pricing information reveals the variety of TOD tariff designs. However, this does not help in understanding the basic challenge facing TOD offerings: relatively low adoption rates by residential customers. One way to gain insight into participation issues is to evaluate standard and TOD bills for customers for some of the TOD rates reviewed in this study.

By calculating comparative bills for a range of load factors it is possible to understand what types of customers are likely to be attracted to TOD service, as well as the likelihood of participation. Without knowledge of actual load factors, these calculations can only be illustrative, but they do indicate the ratemaking challenge. Table 3.1, below, provides such calculations.

The calculations apply to three utilities, Georgia Power, Arizona Public Service, and Xcel Energy North Dakota, as a benchmark. A customer of average size total consumption has four bills calculated for each tariff. (Note that size increases with load factor, so the average customer is

depicted in one of the central columns.) The monthly bills, TOD bill savings amount, and percentage are depicted. The last line provides an estimate of annual total TOD bill savings.

In each case, the attractiveness of the TOD tariff increases with load factor, as an increasing share of load occurs in off-peak hours. Additionally, it appears that some tariffs, Arizona Public Service's in particular, are more attractive than the base tariff at any of the load factors presented. Not surprisingly, APS's TOD participation rates are reputed to be relatively high.<sup>14</sup> In contrast, at Xcel Energy North Dakota, load factor must be relatively high to create a billing advantage for TOD service.<sup>15</sup>

**Table 3.1**  
**Comparative Monthly Residential Bills of TOD and**  
**Standard Tariffs, Selected Utilities**

<b>Georgia Power</b>				
Load Factor	53%	58%	63%	68%
Standard	\$ 99.62	\$ 107.76	\$ 115.85	\$ 123.94
TOD	\$ 101.77	\$ 108.69	\$ 115.61	\$ 122.53
TOD Bill Savings	\$ (2.15)	\$ (0.93)	\$ 0.25	\$ 1.42
TOD Bill Savings (%)	-2.2%	-0.9%	0.2%	1.1%
Annual Bill Savings	\$ (25.76)	\$ (11.13)	\$ 2.96	\$ 16.98
<b>Arizona Public Service</b>				
Load Factor	58%	63%	68%	73%
Standard	\$ 143.63	\$ 154.39	\$ 169.78	\$ 180.54
TOD	\$ 128.93	\$ 135.23	\$ 142.86	\$ 149.16
TOD Bill Savings	\$ 14.70	\$ 19.16	\$ 26.92	\$ 31.38
TOD Bill Savings (%)	10.2%	12.4%	15.9%	17.4%
Annual Bill Savings	\$ 176.39	\$ 229.95	\$ 323.01	\$ 376.57
<b>Xcel ND</b>				
Load Factor	57%	63%	70%	73%
Standard	\$ 75.52	\$ 82.76	\$ 90.00	\$ 93.61
TOD	\$ 78.31	\$ 82.51	\$ 86.71	\$ 88.81
TOD Bill Savings	\$ (2.79)	\$ 0.25	\$ 3.29	\$ 4.81
TOD Bill Savings (%)	-3.7%	0.3%	3.7%	5.1%
Annual Bill Savings	\$ (33.45)	\$ 3.00	\$ 39.45	\$ 57.68

Computational Note: annual totals use unrounded monthly bill savings while the table displays two decimal places only.

<sup>14</sup> A telephone interview in 2010 produced an estimate by APS of 51% of customers and 75% of load as participating in one of their TOD programs. Source: Pacific Gas & Electric Company, Application 10-02-028 (U39E) Exhibit No. (PGE-2), 2010, April 3, 2012, Rate Design Window Rebuttal Testimony, *Rebuttal Testimony of Dr. Stephen S. George*, p. 9-18, line 16ff.

<sup>15</sup> Again, note that the load factors are illustrative.

Table 3.1, above, makes clear the central dilemma of TOD rate design: revenue recovery versus attraction of customers. Unless potential response benefits are significant, attempts to make a TOD rate revenue neutral to the comparable standard tariff will result in low participation. Additionally, TOD rates by definition favor high load factor customers, and thus have difficulty attracting customers with air conditioning and space heating load that is most readily movable to off-peak or shoulder hours. Keeping peak periods narrow helps with the latter problem. Recognizing the system benefits of price response helps with the former. Recognizing that high load factor customers will disproportionately adopt TOD service provides further assistance.

### 3.3 Review of Specific TOD Designs

The following TOD rate design descriptions highlight programs of particular interest among those investigated and whose salient features were mentioned in the various design and pricing features above.

#### Arizona Public Service

This utility's TOD tariff offerings are notable due to the relatively high rate of participation. The bill comparison computations suggest that bill savings play a significant role in this fact. The base TOD tariff, ET-2, is a two-season, two-period design with a peak season price ratio of 3.9. The utility also offers separately CPP and a PTR pilot, providing TOD pricing to suit diverse customer tastes. Their ECT-2 tariff is interesting for its use of demand charges with TOD, a design that may become more common, for both conventional non-time-varying residential tariffs and TOD designs.

#### Gulf Power

Gulf Power's RSVP tariff is the utility's only TOD tariff, and it offers customers a rate with a CPP provision. This is a notable departure in that other utilities tend to offer TOD service and a CPP option separately. (This might suggest that the tariff ought not to be included in this review, but it is instructive that one utility concluded that a traditional TOD rate was not cost effective.) The rate is instructive in that it makes use of three-period pricing and adds a fourth period—the critical-peak period—at short notice, and at any time or date. As well, the utility has two weekend pricing periods, year-round, instead of making all weekend hours off-peak. Lastly, the rate allows explicitly for electric vehicle charging without including extra pricing provisions. (A technical note: the price variation of RSVP is actually found in an associated rider, the Energy Conservation Cost Recovery schedule.)

#### Minnesota Power

Minnesota Power has grafted TOD service onto block pricing. The normal difficulty with such an approach is that customers with high shares of load on high-priced blocks tend to join TOD service and experience bill savings, while those served predominantly on low-priced blocks tend to avoid TOD. The TOD rider concept leaves the base tariff in place and charges a price premium on peak period consumption and a price discount (in effect, a rebate) on off-peak consumption. This avoids the selection difficulties of offering a TOD *rate* to blocked tariff

customers. Since Xcel Energy does not have blocked pricing in North Dakota, that challenge does not present itself. Nevertheless, the design concept is worth noting.

#### Oklahoma Gas & Electric

Oklahoma G&E offers several TOD rates to residential customers. This sub-section reviews the R-TOU “static” rate design, but the utility also offers a CPP tariff and a variable CPP (VPP) tariff. VPP provides day-ahead pricing with a CPP “over-call” provision that permits introduction of a critical-peak price at short notice. All share the same pricing periods: the peak period is summer non-holiday weekdays from 2:00 to 7:00 pm. Additionally, non-summer pricing is a simple declining block price with one step at 600 kWh per month, presumably to allow for space heating. Thus, the utility offers to create a portfolio of TOD products that allow active load managers to take advantage of demand response products alongside a traditional TOD offering.

The R-TOU tariff also includes the first-year “best bill” customer risk mitigation provision, and requires a one-year commitment. A senior citizen lump sum discount in summer further attracts their target customers.

#### Salt River Project

Salt River Project’s TOD programs have a number of interesting features. First, they have the only program reviewed with three seasons of TOD pricing. Their “summer peak” season is July and August, priced differently from their “summer” season of May, June, September, and October. Both those seasons have similar peak hours, but these hours differ from their split peak hours in winter. Second, their pricing is unbundled, although there is no evidence of customer choice. Their tariffs provide detail on all functional components of service, plus an array of fuel charges and trackers.

Third, they offer both the standard TOD E-26 tariff and an experimental alternative with a three-hour peak with three possible alternative start times (2:00, 3:00, or 4:00 pm), in the same style as WE Energies. This approach facilitates increasing the on-peak to off-peak price ratio. In combination, these structural alternatives allow the utility to achieve what might otherwise be achieved with a two-season three-period tariff by way of on-peak to off-peak price differentiation.

#### San Diego G&E

San Diego G&E has demonstrated that one can combine TOD and blocked pricing. The rate offers TOD prices that differ across the four tiers and two seasons. Thus, there are four on-peak prices, ranging in summer from about \$0.17 to \$0.57, and four off-peak prices, ranging from \$0.15 to \$0.33 per kWh. The result produces low price ratios for Tier 1 service and increasing price ratios through Tier 4. A second set of four prices for each pricing period applies in the non-summer period. Because of complexity of this structure, the Minnesota Power TOD rider approach appears cleaner and simpler.

#### Southern California Edison

Southern California Edison has unbundled TOD service in its TOU-D-1 tariff, with two seasons and two pricing periods per season. The tariff’s distinguishing feature is the presence of a peak-

time rebate PTR element, which appears to be mandatory. The utility can call critical-peak periods at any time without restriction, and the customer has a predetermined “customer specific reference level” (CSRL) that represents usage in the absence of a critical-peak period. Any departures from this level are priced at the very high PTR price. Load reduction in this period from the CSRL produces large bill savings, while load increases produce large bill increases. Like Gulf Power, SCE does not see the need for a traditional TOD rate, treating their current rate as their simplest time differentiated residential rate.

### WE Energies

The central feature of WE Energies’ approach to TOD service in Wisconsin is recognition of customer diversity and risk management. One rate, Rg2, has two levels of service with differing price ratios, a two-period structure in each season, and choice in 12-hour peak period start time (7:00, 8:00, 9:00, or 10:00 a.m.). The second, Rg3, has three time periods, which allows for a higher price ratio between on-peak and off-peak periods. Customers can depart at any time but must wait a year to reapply. Furthermore, large customers with over 20,000 kWh per year are put on the rate mandatorily. Mandatory participation is a virtually unknown provision elsewhere, based on the tariffs reviewed.

However, two cautionary aspects of these designs arise. First, perhaps for the sake of product simplicity, there are no seasonal differences in peak time period. Second, it is not clear that the complexity of staggered start times is worth the effort at a time when regional wholesale price, and not system peak demand, is more important in obtaining customer response. If customers shift out of a peak period and set a new peak, this is unlikely to threaten system security.

### 3.4. Summary

This review has revealed that TOD rates are predominantly two-season, two-period (lacking a shoulder) in structure, with the timing of peak periods being utility specific. Even utilities in close geographic proximity can have significantly different pricing periods, perhaps for reasons of cost, perhaps for reasons of customer marketing or internal operations. Prices are quite variable, and there is loose correlation between on-peak and off-peak pricing. There seems to be some negative correlation between length of peak period and peak to off-peak price ratio at least during the summer peak season.

Utilities generally try to deter short-term strategic participation, requiring either a one-year commitment or placing a one-year minimum lag on reapplying after departure. Utilities are not systematic in providing other customer risk management devices such as bill minimization for the first year.

Bill comparisons suggest that utilities do not uniformly attempt to meet a particular standard of revenue neutrality in setting price levels. The computations of illustrative bill comparisons suggest that not striving for revenue neutrality strongly influences participation. There remains the issue of the degree to which lower TOD bills can be justified. Load factor considerations appear to be important in determining price levels.

The designs reviewed here present several possible lessons for the review of Xcel Energy's North Dakota TOD rate. One lesson pertains to the selection of number of seasons and pricing periods. Most utilities appear to favor simplicity, preferring two seasons and two time periods to more of either, although there are exceptions. Some considerations related to Xcel Energy's North Dakota circumstances may run counter to the simple structure.

- Space heating in winter in North Dakota is significant. A non-summer price covering all but two or three summer months might or might not provide an efficient price signal for the heating season. Three seasons would help to delineate the heating season, if that is cost effective.
- If high price ratios to encourage load shifting are important, then a three-period approach, at least for summer, and perhaps winter too, would help to achieve this if the two-period model yields relatively low price ratios. (The next section of the report provides estimates of marginal cost ratios.)
- Depending on the pattern of marginal costs in off-peak hours, three seasons and/or three periods might provide a superior platform for electric vehicle charging if future allowance for this service within the updated tariff is a consideration. (The review does not provide evidence in this regard.)
- Some utilities strive to make prices in different seasons identical to limit the number of prices. Depending on the range of marginal cost values between time periods, simplification may make sense.

Another design point to note is that some utilities do not use TOD pricing in non-summer seasons, reverting to flat or block pricing. While not widely used, this can be a practical simplification, given that customer response at price ratios below 3:1 is hard to detect in statistical evaluations of response. Many non-summer price ratios reviewed here are well below this threshold. However, inability to detect price response does not necessarily imply that it does not exist. Simplifying to a single price likely imposes a trade-off in reduced pricing efficiency, so failure to reach the 3:1 threshold does not indicate conclusively that a TOD structure should be abandoned.

Measures to attract customers such as multiple peak period start hours and guaranteed minimum bill provisions for the first year are not widely used and do add administrative complexity, but may be worth reviewing.

- Multiple peak hours appear to be unnecessary from a utility operations perspective, since the impact of load shifting on the location of system peak is less important than it used to be, given the rise of regional transmission organizations and increased power trading.
- A guaranteed minimum or best bill provision complicates billing somewhat but may reduce customer *status quo* bias against TOD service, improving ability to attract new customers.

Once a customer agrees to participate in TOD pricing, almost all utilities require a one-year commitment or a one-year wait time for those who depart TOD service to reapply. This seems essential to deter seasonally timed rate switches.

Another intriguing concept is demand charges, which advances in metering appear to have made possible. However, demand charges have some cautionary features with respect to TOD service if the underlying standard tariff does not also have a demand charge.

- A new demand charge complicates TOD service and presents a possible deterrent to customer participation.
- The pricing efficiency benefits of demand charges may be overstated. Better correspondence of rates with unit costs is achieved, but customers' perceived cost of additional consumption still incorporates a demand charge component.

Increased customer charges to cover the incremental costs of TOD service are not universally used. This tendency is likely due to theoretical and practical considerations.

- It is not clear that the incremental costs of TOD service (billing, metering & communication, and customer support) should be borne entirely by TOD customers, since their load shifting behavior could create benefits for all customers.
- Utilities with incremental customer charges impose bill increases that have the potential to deter participation.

The TOD designs reviewed here do not deter the future subsequent introduction of dynamic pricing (CPP, PTR, etc.). Several utilities offer one of these options in a separate tariff. Consequently, Xcel Energy would not appear to be ruling out any future options by adopting any of a wide variety of structural changes.

Conversely, there does appear to be some potential interaction between TOD design and the offer of EV service. A TOD design that might in the future include EV service might want to ensure pricing accuracy for a large load, suggesting that more seasons and time periods would help to develop EV pricing within a TOD tariff. However, some utilities develop their own EV tariffs, necessitating a separate account/meter arrangement. This approach would facilitate TOD structure and pricing decisions without having to consider electric vehicle rate support.

Competitive markets where TOD service is offered may provide guidance for regulated markets. Unbundling of charges by function facilitates development of retail customer choice. Xcel Energy can evaluate whether this is an immediate consideration for the North Dakota service territory. Unbundling produces a significant expansion in the number of customer charges and energy prices on a bill, suggesting that this be avoided until customer choice for mass market customers arrives.

Deregulation provides opportunities for the introduction of exotic or niche products like the free nights and weekends products previously described above. These innovations offer some ideas for thought.

- Pricing of this sort is less efficient in that prices move away from marginal cost in each time period.
- Customer reaction so far has been strong, both in favor and in opposition. The risk to a regulated utility is that some customers will sign up for such a product and then complain to their utility or the regulator when they find that their bill increases

measurably if they fail significantly to shift usage to off-peak hours, assuming that they are not already strongly off-peak users.

- Customers may find the simplification of a zero price for certain hours to be attractive, and the price may be quite successful in achieving price response.

The challenge of attracting customers to TOD service appears to have been met, with varying degrees of success, with several devices:

- High load factor customers have a natural tendency to disproportionately adopt TOD service due to the bill savings that arise from having relatively more load off-peak than the average customer. Pricing that recognizes this differential has the potential to improve the cost effectiveness of a TOD offering.
- Risk minimizing features such as minimum billing in the first year may reduce customer hesitancy toward a new product, at the cost of some revenue attrition to the utility and/or its other customers.
- Design of seasons, pricing periods, and prices may help to create load shifting benefits to supplement immediate bill savings for customers.

#### **4. MARGINAL COSTS AND OPTIMAL TIME PERIODS FOR TOD IN NORTH DAKOTA**

The development of prices of an updated TOD rate in North Dakota will need to rely on forecasts of the marginal cost of energy (and capacity). This section provides definitions of the relevant costs and makes use of data from Xcel Energy to provide forecasted marginal costs for possible TOD time periods.

The selection of TOD time periods can be viewed as involving two linked steps: the selection of a preferred time period structure—number of seasons and pricing periods in each season—and the selection of the specific hours to define each period. The choice of time period *structure* is a matter of discretion for the utility, based on product objectives and upon the differences in marginal costs between periods for alternative structures. For example, little TOD variation might suggest use of relatively fewer time periods, while large systematic differences might suggest recognition of distinct time periods.

Within a given structure, time periods for most utilities are often based on informed intuition about peak time periods. CA Energy Consulting has been applying a statistical method for many years to help utilities to identify optimal TOD pricing periods, and we describe and apply this method here. This method is implemented in a spreadsheet model called *PRIOPT*.

##### **4.1 Methods**

The marginal cost of electricity is the change in electricity costs that accompanies a change in load. For generation services, there are two types of such costs: energy costs, including the costs of transmission constraints, transmission losses, and distribution losses in bringing power from generators to consumers; and capacity costs, considering both losses and the impacts of loads upon capacity requirements.<sup>16</sup> In the markets of the Midcontinent Independent System Operator (MISO), marginal energy costs at the transmission level are measured by locational

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<sup>16</sup> We have not performed an analysis of the marginal costs of transmission and distribution services.

marginal prices (LMPs), while marginal capacity costs at the transmission level are measured by capacity prices. Consequently, for a consumer at a location  $j$ , marginal cost in any hour  $h$  can be expressed as follows:

$$\begin{aligned} MC_{jh} &= MEC_{jh} + MCC_{jh} \\ &= VAF_j * [LMP_{jh} + (1 + PRM_j) * CP_{jh}] \end{aligned} \quad (1)$$

where  $MEC_{jh}$  is the marginal energy cost at location  $j$  in hour  $h$ ,  $MCC_{jh}$  is the marginal capacity price at location  $j$  in hour  $h$ ,  $VAF_j$  is the voltage adjustment factor applicable to location  $j$ ,  $LMP_{jh}$  is the locational marginal price at location  $j$  in hour  $h$ ,  $PRM_j$  is MISO's target planning reserve margin at location  $j$ , and  $CP_{jh}$  is the capacity price at location  $j$  applicable to hour  $h$ .<sup>17</sup>

For purposes of statistical analysis of time periods, we define “best” TOD periods as those that minimize the variance of LMPs within periods. This variance inevitably goes down as the number of TOD periods goes up. Consequently, the number of TOD periods must be determined by a judgment call that considers both rate simplicity (fewer periods being better) and the amount of reduction in the variance that can be achieved by adding more periods. The *PRIOPT* model computes the relevant statistics, described below, for a given number of seasons and time periods. Viewing the results for each specification facilitates the subjective choice of the preferred number of seasons and time periods.

For a consumer group at location  $j$ , variance is measured by the following equation:

$$Variance_j = \sum_T \sum_{h \in T} [Q_{jh} * (LMP_{jh} - AVGLMP_{jT})^2] \quad (2)$$

where  $T$  is an index of TOD periods,  $h$  is an index of hours,  $Q_{jh}$  is the load of consumer group  $j$  (in this case, Xcel Energy's North Dakota residential customers) in hour  $h$ , and  $AVGLMP_{jT}$  is the load-weighted average LMP over TOD period  $T$ , defined as follows:

$$AVGLMP_{jT} = \sum_{h \in T} (Q_{jh} * LMP_{jh}) / \sum_{h \in T} Q_{jh} \quad (3)$$

When the *PRIOPT* model finds the set of TOD periods  $T$  that minimizes the variance of equation 2, we also find the average LMP for these same periods. The marginal cost that we attribute to any off-peak TOD period  $T$  is then:

$$MC_{jT} = VAF_j * AVGLMP_{jT} \quad \text{for off-peak periods} \quad (4a)$$

The marginal cost that we attribute to any on-peak TOD period  $T$  is:

$$MC_{jT} = VAF_j * [AVGLMP_{jT} + (1 + PRM_j) * CP_{jh}] \quad \text{for on-peak periods} \quad (4b)$$

<sup>17</sup> “Location  $j$ ” may be a node, a load zone, or a voltage level, depending upon the parameter and the workings of the MISO market.

where  $CP_{jh}$  equals the MISO capacity price per MW-week divided by the number of peak hours per week.<sup>18</sup> Note that the capacity price plays no role in the determination of the TOD pricing periods, but instead enters the marginal cost calculation after the TOD pricing periods have been identified.

## 4.2 Data

The necessary data are hourly loads, hourly LMPs, and three parameters.

### 4.2.1. Xcel Energy's North Dakota Residential Loads

We derived 8,760 forecast hourly loads for 2015 for Xcel Energy's North Dakota residential customers by combining the following information provided by Xcel Energy:

- the 8,760-hour residential load shape from the 2012 North Dakota rate case for Test Year 2013; and
- forecast monthly North Dakota residential sales for 2015.

Hourly loads for Test Year 2013 were assigned to all the hours in the 2015 calendar, with due consideration for weekends and holidays. Each month's loads were scaled up or down so that the monthly sums match the monthly forecast loads.

### 4.2.2. North Dakota LMPs

We derived 8,760 forecast hourly LMPs for 2015 for Xcel Energy's North Dakota service territory by combining the following information:

- forecast for 2015 of 8,760 hourly LMPs for MINN.HUB (*i.e.*, Xcel Energy in Minnesota and neighboring states);
- hourly historical LMP data for 8/1/11-7/31/14 for MINN.HUB and for Xcel Energy's load zones in North Dakota (OTP.NSP and GRE.NSP);<sup>19</sup> and
- the shares of Xcel Energy's North Dakota customers who are in each of the two load zones.<sup>20</sup>

For each North Dakota load zone, we calculated a monthly ratio of hourly LMPs in North Dakota to hourly LMPs for the Minnesota hub based upon the average ratios of the past three years. For example, the ratio for OTP.NSP for January was calculated as:

$$RATIO_{OTP,JAN} = \sum_{h \in JAN} LMP_{OTP,h} / \sum_{h \in JAN} LMP_{MINN,h} , \quad (5)$$

where the summations are over all three Januaries in the 36-month historical period. We then used these ratios to derive LMPs for the OTP.NSP and GRE.NSP load zones, scaling each hour's

<sup>18</sup> MISO's capacity prices are actually set on a per-MW-day basis, including both weekdays and weekends. Because Xcel Energy's peak periods occur on weekdays only, the method described in the text attributes the capacity costs of all days, including both weekdays and weekends, to the peak period hours.

<sup>19</sup> From the MISO website.

<sup>20</sup> The Company provided data showing that these shares are 78.89% for OTP.NSP and 21.11% for GRE.NSP. These shares are calculated excluding the customers of a third load zone, WAUE.NSP, which accounts for only 0.28% of Xcel Energy's total North Dakota customers.

2015 forecast for MINN.HUB by the appropriate ratio. This gave us 8,760 hourly LMPs for 2015 for each of the two load zones. We then derived the 8,760 hourly LMPs for Xcel Energy’s whole North Dakota service territory by computing a load share-weighted average of the LMPs for the two load zones.

#### 4.2.3. Parameters

We used the following values for three parameters:

- *Voltage adjustment factor (VAF)*: Because the load data are at the generator bus, no adjustment is necessary, so VAF equals 1.000.
- *Planning reserve margin (PRM)*: This has a value of 0.142.<sup>21</sup>
- *Capacity price (CP)*: For MISO load resource zone 1, which includes Xcel Energy’s North Dakota service territory, the capacity price is currently \$3.29 per MW-day.<sup>22</sup> As noted above, this value, expressed as dollars per MW-week, needs to be divided by the number of peak hours per week.

### 4.3. Findings

#### 4.3.1. Quantitative Results

The *PRIOPT* model finds that the summer season is best characterized as consisting of July and August. Adding June or September increases the variance measured by equation 2. If there is a winter season, it is best characterized by the three months of December through February. Adding March slightly increases the variance.

Table 4.1 below shows the optimal TOD periods and resulting wholesale prices applicable to the case in which there are two seasons and two pricing periods per season. The summer peak-to-off-peak marginal cost ratio barely exceeds two, while the non-summer ratio is 1.57.

**Table 4.1**  
**Two Seasons, Two Periods per Season**

Season	Months	Hours		Marginal Costs \$/MWh		P/O Ratio
		On-Peak	Off-Peak	On-Peak	Off-Peak	
				[BEGIN TRADE SECRET]		
Summer	July-Aug	9am-10pm	10pm-9am			2.01
Non-Summer	other	7am-10pm	10pm-7am			1.57
				[END TRADE SECRET]		

<sup>21</sup> North American Electric Reliability Corporation, *2013 Long-Term Resource Assessment*, December 2013, p. 54.

<sup>22</sup> MISO, 2014/2015 Planning Resource Auction (PRA), presentation, undated. This price is well below the \$16 per MW-day price of MISO’s other load resource zones because of transmission constraints that limit power exports from load resource zone 1.

Table 4.2 below shows results when a third season is added. The third season reduces variance by a modest 6.4%, indicating slightly greater pricing accuracy, which can be seen in the significant differences between winter and shoulder season prices. In other words, the division of the non-summer season into winter and shoulder seasons allows for greater differentiation in prices between seasons.

**Table 4.2**  
**Three Seasons, Two Periods per Season**

Season	Months	Hours		Marginal Costs \$/MWh		P/O Ratio
		On-Peak	Off-Peak	On-Peak	Off-Peak	
				[BEGIN TRADE SECRET]		
Summer	July-Aug	9am-10pm	10pm-9am			2.01
Winter	Dec-Feb	7am-9pm	9pm-7am			1.57
Shoulder	other	7am-11pm	11pm-7am			1.58
				[END TRADE SECRET]		

Table 4.3 below adds a third period to each of the three seasons. Addition of the third period reduces variance by a further 3.9%, reflecting the greater pricing accuracy associated with giving higher peak prices. The summer peak-to-off-peak price ratio rises a bit, but still is not much above 2.00.

**Table 4.3**  
**Three Seasons, Three Periods per Season**

Season	Months	Hours			Marginal Costs \$/MWh			P/O Ratio
		On-Peak	Shoulder	Off-Peak	On-Pk	Shldr	Off-Pk	
					[BEGIN TRADE SECRET]			
Summer	July-Aug	11a-6p	9a-11a/6p-11p	11pm-9am				2.36
Winter	Dec-Feb	7a-12p/5p-8p	12p-5p/8p-10p	10pm-7am				1.73
Shoulder	other	9a-4p	7a-9a/4p-12a	12am-7am				1.78
					[END TRADE SECRET]			

#### 4.3.2. Implications

The quantitative results above have several implications. First, the data indicate the selection of a short summer season of just two months.<sup>23</sup>

Second, given the presence of space heating customers and the marginal cost differences between the winter and the shoulder seasons, it may be useful to have three seasons per year.

<sup>23</sup> This does not mean that periods of high marginal cost/wholesale price cannot occur outside these two months. Instead, it simply means that within-period variance is minimized by selecting a two-month summer season.

If there are three seasons per year, Xcel Energy can use its intuition as the basis for choosing whether March is in the winter or the shoulder season.

Third, unlike most utilities, Xcel Energy does not need to worry about the timing of bills in determining marginal cost. For most utilities, summer peak marginal costs, and the prices derived therefrom, would apply to all bills rendered in the summer months, despite the fact that some energy is consumed prior to summer, and some late summer consumption is billed at non-summer prices. Because Xcel Energy prorates its consumption in billing months with two seasons, the customer is charged a reasonable approximation of summer and non-summer rates. For example, a bill covering the thirty-day period of June 16 to July 15 would have half its consumption charged at non-summer TOD rates and the other half at summer rates. Prorating facilitates accurate seasonal pricing.

Fourth, for a TOD rate to provide benefits from load shifting, customers need to understand easily the prices that they face. It is fairly easy for customers to comprehend two pricing seasons and even three pricing seasons. By contrast, residential customers will find it challenging to keep track of the complex intra-day pricing periods shown in Table 4.3, wherein prices change four times per day in the summer and shoulder seasons and five times per day in the winter season. Such complexity might be programmed into advanced thermostats, but managing consumption of other end uses would be relatively more difficult in a three-period structure.

In fact, if Xcel Energy selects a two-period structure, the utility might also wish to consider additional pricing period simplification. The time periods shown in Table 4.1 and Table 4.2 could be made uniform among seasons. Customers would find it easier to remember and respond to prices that peak at 8:00 am to 10:00 pm all year long, for example, than to prices that have periods that vary by season. However, such uniformity could reduce the accuracy of the TOD pricing signal.

Fifth, the rather low peak-to-off-peak marginal cost ratios reflect the available forecasts of the relative fuel costs and capacity values of the different TOD periods. Although these ratios do not reflect environmental considerations such as carbon emissions, they would not be raised by such considerations unless it happens, for example, that coal plants are more likely to be at the margin in peak periods than in off-peak periods.

The foregoing implications are applicable to average residential load in North Dakota. However, we note that customers whose load patterns materially differ from the average may derive benefits that are modestly greater or less than the average. This information and the implied pricing are also applicable to new customer uses of electricity such as electric vehicle recharging. As such new uses grow in volume, future re-evaluation and updated analysis could consider the impacts of such new uses on load patterns and LMPs.

## **5. POTENTIAL TO INCREASE THE COST EFFECTIVENESS OF TOD SERVICE IN NORTH DAKOTA**

If Xcel Energy were initiating residential TOD service in North Dakota, instead of considering updating its existing tariff, the utility might select a different structure and pricing than are found in the current tariff. The residential TOD rate structures of other utilities certainly

indicate a broad range of alternatives. Xcel Energy's own objectives might suggest a particular design. For example, a three-season, three-period structure might offer efficient pricing now and a platform for additions in the future (CPP, pricing for electric vehicles, etc.).

However, two material considerations may affect Xcel Energy's plans. First, adopting a more complex structure may involve measurable incremental metering, billing, and customer support/communication costs relative to a simple structure such as that of two seasons and two pricing periods. Second, any modification ought to be significantly different from the current structure. If an otherwise preferred design is not, then it may make sense not to modify the current design or its pricing.

### **5.1 Incremental TOD Customer Support Costs**

The Company has conducted research regarding anticipated incremental metering and billing costs associated with an expanded residential TOD program in North Dakota.<sup>24</sup> This research entailed reviewing the entire metering and billing process: the meters required to support TOD rates, the automated meter reading process, meter data acquisition and storage, and final billing. The costs to make any necessary changes to this process would be considered incremental costs to offer the rate.

#### 5.1.1 Incremental Costs to Support an Expanded Two-Period TOD Program

Xcel Energy reports that its current systems can readily accommodate two-period TOD rates of the sort that the Company offers in North Dakota today. Modifying the current rate by, say, changing the on-peak and off-peak time periods and adjusting the prices, can apparently be accomplished with minor system changes.

Regarding metering, Xcel Energy currently serves its residential customers in North Dakota with conventional watthour meters. The few TOD customers are metered by a two-channel meter capable of recording usage totals for the two periods. Providing new customers with such a meter might cost an incremental \$2.00 per customer-month. This mirrors the extra \$2.00 per customer-month that TOD customers currently pay over standard tariff customers.

Regarding communication and billing, the utility can accommodate an expansion of two-period TOD service in its existing AMR network, and the billing system would not require any changes or upgrades to process bills for an expanded residential TOD population.

#### 5.1.2 Incremental Costs to Support a Three-Period TOD Program

Xcel Energy's research indicates that supporting a three-period TOD rate would require significant changes to metering, communications, and billing. Regarding metering, existing meters are capable of acquiring three data points per billing period, but would need to be programmed and tested to handle the additional data set. This extra cost is nonvolumetric and unrelated to the number of meters put into the field.

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<sup>24</sup> Source: Company-provided information via November 4, 2014 email.

Regarding communications and billing, the automated meter reading network and meter data repository would require modifications in order to accommodate the third time interval. Finally, modifications to the billing system would also need to be made. The Company estimates that the cost of such changes, including the cost of programming and testing the meters, would approach \$250,000.

Based on realistic customer participation rates, the resulting incremental cost of three-period service relative to two-period TOD service would likely exceed \$2.00 per month. This cost would be in addition to the existing incremental cost of TOD metering relative to the standard tariff. (As mentioned above, this latter cost is reflected in the monthly price premium of \$2.00 per customer-month built into the current TOD rate to account for incremental meter costs.)

In brief, expanded two-period TOD service would impose limited incremental costs reflected in the current TOD customer charge premium over that of the standard tariff, while three-period service would require higher incremental costs, due to the expenses necessary to upgrade the utility's capabilities in a number of customer support systems.

## 5.2 Updated Rate Structure

Xcel Energy could update its residential TOD rate structure to adopt one of the recommended time period structures and a retail price that is based on marginal costs forecasted for 2015. If the utility sought to minimize incremental support costs, it could adopt a two- or three-season two-period tariff structure. The on-peak hours would be only slightly different from the current structure of 9:00 am to 9:00 pm. Combining this change with changes to TOD prices that recover current revenue levels but retaining the forecasted on-peak to off-peak price ratio would likely slightly lower on-peak prices and raise off-peak prices. This would reduce benefits available from load shifting and thus reduce the attractiveness of the rate, despite improving pricing accuracy.

Other structure changes, to three periods for example, could improve the rate's attractiveness by narrowing the peak period and increasing the on-peak to off-peak price ratio relative to the forecasted marginal cost ratio. However, even in this case, the price ratio would decrease relative to the current price ratio. The narrower peak period might increase customer and utility benefits from load shifting slightly if this change were to facilitate greater customer price responsiveness in the peak period. However, if the core revenue requirement for TOD service remains unchanged, it would be difficult to attract new TOD customers.

The Settlement Agreement also mentions the importance of exploring the potential effect of new TOD service in reducing the North Dakota jurisdiction's share of costs as determined by its contribution to system peak demand. To achieve such a peak reduction, it would be necessary to find a means of attracting numerous new residential TOD customers and use a high peak period price to cause reduced peak demand contribution from program participants. For example, attracting 2,000 residential customers to TOD service and offering a price that reduced peak consumption by ten percent, (say, 0.4 kW for a customer with 4 kW of peak demand each, or 0.8 MW for all participants combined) might have a slight effect. However, this strategy might require an on-peak to off-peak price ratio that would be difficult to justify

based on the current marginal cost forecast, coupled with an overall price reduction or expensive marketing campaign necessary to attract new customers. Given the possible incremental costs associated with a three-period approach, such a plan would also be problematic.

This hypothetical example highlights the challenge that Xcel Energy (and other utilities) face in promoting residential TOD service. Forecasted marginal costs and cost-based pricing methods limit the ability of TOD service to offer load modification benefits to participants sufficient to overcome the incremental billing, metering, and customer support costs of a three-period program that maximizes price ratios. Reductions in overall average price may have some degree of cost justification, but possibly not sufficient to avoid cross subsidization by non-participants or other rate classes or, alternatively, subsidization by the utility in the form of reduced rate of return.

Xcel Energy could potentially also increase the attractiveness of its TOD product slightly by adopting a first-year minimum bill provision such as that of Oklahoma Gas & Electric. The revenue attrition aspects of this offer might be relatively small while the offer might significantly lower the risk hurdle for customers who might otherwise hold back from committing to TOD service. However, this change is likely to be of secondary importance relative to bill total comparisons, and participation improvement is likely to be minor.

In summary, Xcel Energy's North Dakota residential TOD service could be modified to update product pricing and slightly increase attractiveness for new customers at low cost. To control cost, the Company could choose a two-period approach (no shoulder period) to offer less complexity for customers and achieve lower administrative cost for the utility. Addition of a minimum bill provision would also appear to be beneficial.

Increasing participation would require bill reductions relative to the current rate. Spreading existing incremental customer costs of \$2 per customer-month across all residential customers would help, and could be justified based on theory (shared benefits of load shifting by non-participants) and practice (widespread approach by the industry). However, more significant bill reductions may be necessary to achieve a target of, say, 2,000 customers, whose load shifting would materially reduce jurisdictional and utility capital costs. These might be cost justified based on the above average TOD customer load factor, but might involve a certain amount of cross subsidy as well.

### **5.3 Conclusion**

Xcel Energy has investigated whether or how the current residential TOD service can be updated so that it will:

- provide accurate and clear price signals to customers;
- help reduce North Dakota's contribution to the Company's peak periods; and
- minimize the incremental costs to administer the TOD rate.

### Accurate and Clear Price Signals

A TOD rate delivers price response benefits best if its prices are based on (forecasted) marginal costs, since these costs tell customers the value to society of the resources being used. However, prices must also recover required revenues, including transmission and distribution costs, with the result that retail price must differ from the marginal cost of generation services. Marginal costs are, therefore, a necessary guide to TOD pricing but not entirely determinative.

CA Energy Consulting has explored alternative TOD pricing structures and estimated forecasted marginal costs for preferred time periods. We find that the current TOD pricing structure is reasonably close to the variance-minimizing time periods and seasons of the two-season, two-period structure that we selected via the *PRIOPT* model and is similar to many of the designs in use elsewhere.

The current on-peak to off-peak price ratio is somewhat above the forecasted 2015 marginal cost ratio for the selected time periods. Updating the price ratio to better reflect this marginal cost ratio might improve pricing accuracy, but in the process would weaken the benefits to customers of load shifting and reduce the rate's attractiveness to prospective TOD customers. This outcome would be slightly more economically efficient but would work slightly against the second objective of the Settlement Agreement, reducing Xcel Energy's North Dakota peak demand.

An updated three-period alternative might provide even more accurate pricing, although it is not clear whether such a design would be generally superior to a two-period structure. Three-period designs offer greater pricing accuracy at the cost of increased price complexity and thus may further reduce TOD attractiveness to customers.

### Peak Period Reduction and Customer Participation

Modifying time structure and price ratio do not appear to have the potential to increase participation in residential TOD service significantly. First, updating the current tariff would slightly narrow the on-peak to off-peak price ratio, reducing the scope for customer benefits derived from load shifting. Second, the bill comparison analysis suggests that overall bill savings or some other financial benefits are essential to increasing participation. Such an increase is essential if a reduction in North Dakota's peak demands is to be achieved via residential TOD service.

As noted above, participation probability can be enhanced by not imposing incremental customer costs on participants, which may be justified based on the belief that participants may shift load and reduce costs to all customers. An additional consideration is that the advent of smart metering, may at some point, provide mass market customers with interval data recorders, reducing the incremental metering cost of TOD service to zero, or nearly zero. This suggests that it may not be harmful to collect incremental metering costs from all customers, based on the argument that the costs of the transition to smart metering should be broadly borne.

Avoiding passing on incremental metering costs to participants would not likely be sufficient to produce substantial conversion to TOD service, since customers have a preference for rate simplicity and a *status quo* bias that deters conversion by increasing the size of expected benefits necessary to induce conversion to TOD service. Such benefits would need to arise from bill savings additional to those derived from load modification in response to TOD pricing. The associated bill reductions would constitute a cross subsidy from other customers unless the updated TOD rate were to attract customers who have a lower cost to serve than the average residential customer.

#### Minimizing Incremental Costs

CA Energy Consulting obtained information from Xcel Energy on the incremental customer support costs for updated TOD service in North Dakota. This support cost information indicates that a two-period TOD structure minimizes the incremental costs to administer an expanded and updated TOD rate. The incremental costs of three-period service relative to two-period service provide further weight to the perspective that the current structure, or an updated two-period structure, would meet the terms of the Settlement Agreement at lower incremental cost.

#### Summary

Xcel Energy appears to face the same challenge of other utilities contemplating residential TOD service: attracting customers to an accurately priced TOD rate requires overall price (bill) reductions (or corresponding non-price benefit increases) substantial enough to induce customers to overcome biases against changing to a new rate and the increased complexity of TOD pricing. Customers who convert to TOD service benefit from the combination of instant bill reductions and price response. Combined anticipated revenue attrition and incremental program costs must be offset by the system benefits from TOD customer price response, reduced jurisdictional costs, and offsetting revenue recovery from non-participating customers to yield a cost effective outcome.

Thus, expanding participation in the current North Dakota residential TOD program to achieve peak load reduction is feasible, but potentially difficult to achieve cost effectively. In the long term, with the arrival of advanced metering, the balance of benefits and costs may shift. Introducing a CPP element would further complicate TOD service for customers and the utility, but might attract certain customers whose price response to extremely low reserve situations would expand benefits further. However, for the present, TOD service updates are challenging to justify.