Canadian Manufacturers & Exporters

Manufacturiers et Exportateurs du Canada

INDUSTRIAL RATES AS A GROWTH DRIVER IN OTHER JURISDICTIONS

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OPENING LETTER

On behalf of Canadian Manufacturers & Exporters, Nova Scotia (CME-NS), I am pleased to present this study, *Industrial Rates as a Growth Driver in Other Jurisdictions*, authored by Navigant Consulting Ltd. and providing a comparison of Nova Scotia Power Inc. (NSPI)'s industrial rate structures for electricity with other North American and European jurisdictions.

Today's manufacturers compete in a global marketplace, with changing economic conditions involving factors they have little control over. There has been a considerable decline in the manufacturing sector with recent sales figures indicating a recalibration from 2008 levels. In Nova Scotia, we have lost a large number of jobs. In 2006 we had 39,100 people employed in manufacturing in Nova Scotia. In September of 2014 we had 28,000 jobs; a 28 per cent decrease. The decline in our manufacturing sector is the result of several factors. One of the factors is our cost of energy and in particular our cost of electricity.

The Navigant Study for CME revealed that Nova Scotia's industrial customers have one of the highest relative costs for electricity in North America. This is separate from the fact that the power costs for both residential and industrial are among the highest in Canada. Two thirds of the jurisdictions surveyed have a cost environment more favorable to industry relative to their own residential customers than Nova Scotia's.

The study draws from the jurisdictions of California, Iowa, Pennsylvania, Texas, Ontario, Ireland and Germany to suggest a number of innovative measures to improve the attractiveness of the cost environment in Nova Scotia.

When the cost of doing business is high, everyone is impacted as industry looks for ways to reduce costs to remain competitive. Attracting and retaining industry is challenging when energy input costs are among the highest in North America. If we want to ensure our manufacturing jobs remain in Nova Scotia, we need to create an environment that fosters industrial economic stability and growth.

With the province's strong economic mandate and ongoing Electricity System Review, now is an opportune time to advance innovative measures to support industry and economic development.

I encourage you to review the study, reflect on the findings and discuss them widely with your networks.

Carole Lee Reinhardt,
Vice President, CME Nova Scotia

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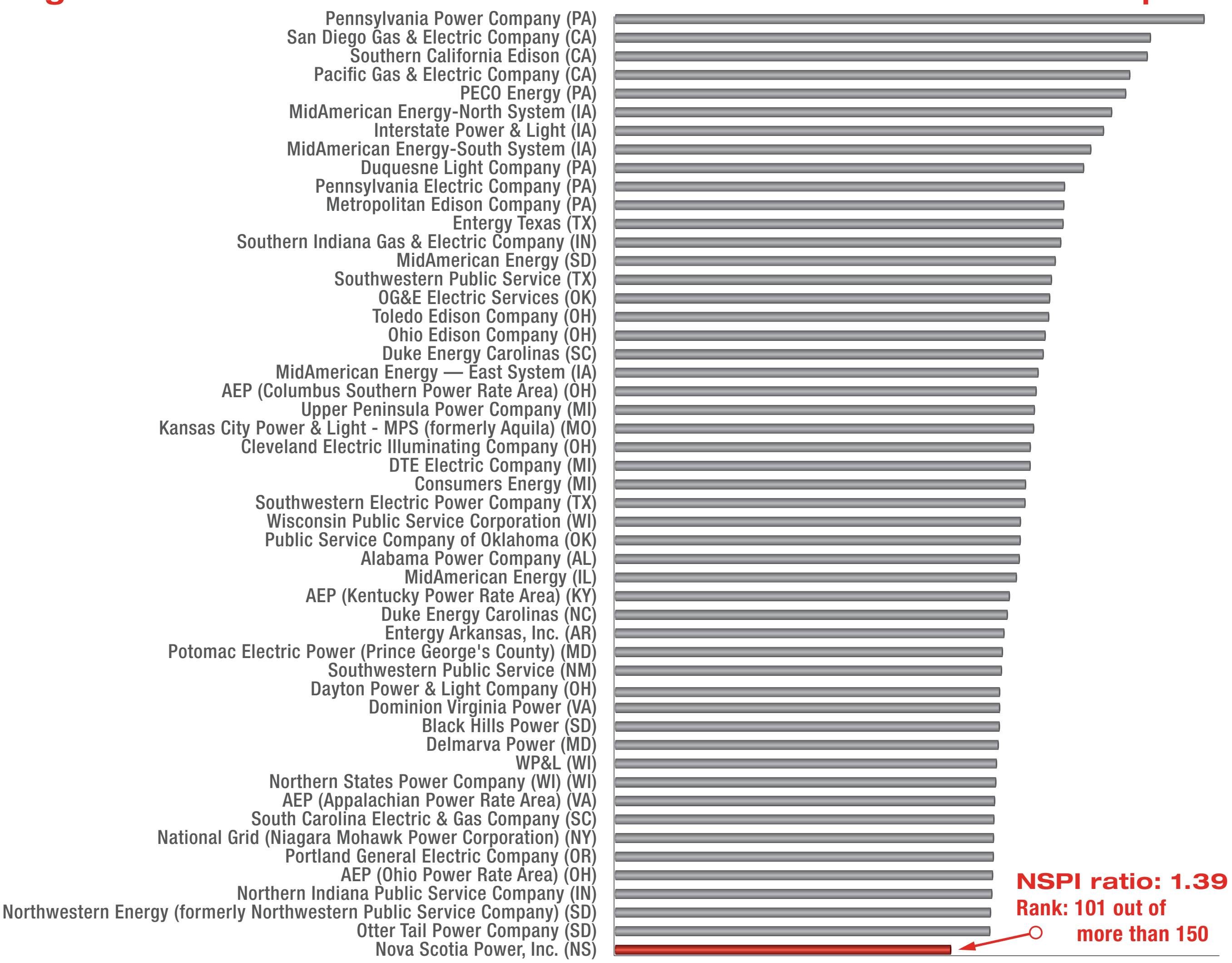
1. EXECUTIVE SUMMARY

Canadian Manufacturers & Exporters, Nova Scotia (CME-NS) engaged Navigant Consulting Ltd. (Navigant) to survey a number of jurisdictions in North America and Europe to help CME-NS better understand how “standard” industrial rates compare to residential rates in those jurisdictions, the prevalence and design of load attraction or retention tariffs, and the prevalence and design of other programs or incentives that work to lower the effective cost of electricity for industrial customers.

The principal finding of Navigant’s survey of industrial rates is that the cost of electricity for industrial customers, relative to the cost of electricity for residential customers, is higher in Nova Scotia than in a large number of other North American utilities or jurisdictions.

In this case, the relative cost of electricity to industrial customers is defined as the average residential unit cost of electricity (i.e., per kilowatt-hour [kWh]), divided by the average industrial unit cost of electricity. The lower this ratio is, the higher industrial electricity costs are relative to residential electricity costs. Figure ES-1 illustrates the survey’s principal finding. This figure compares the top 50 highest ratios in North America to that of Nova Scotia Power, Inc. (NSPI).[i]

Figure ES-1. North American Residential to Industrial Cost Ratios — Top 50



Source: Edison Electric Institute

[i] *Note that the Edison Electric Institute (EEI) report from which these figures are drawn provide costs for over 150 utilities. Only the 50 utilities with the highest ratios, and NSPI, were included on this graph for reasons of legibility. Had all utilities been shown on this chart, NSPI would appear approximately in the bottom third.*

Navigant's principal finding was an outcome of the first phase of this survey of industrial electricity costs. In this first phase, Navigant conducted a high-level survey of the ratio of residential to industrial electricity costs in the majority of North American and European jurisdictions to determine in which jurisdictions industrial electricity costs, relative to residential electricity costs, were lowest.

In all but two of the 160 utilities included in the Edison Electric Institute (EEI) study that provides the basis for Figure ES-1, above, this ratio was above one. That is, in nearly 99 per cent of the utilities surveyed by the EEI, the average cost per kWh was higher for residential customers than it was for industrial customers. The underlying reason for this is simply that in general large industrial customers' higher load factors (i.e. the ratio of average demand to peak demand) mean that their contribution to demand-related system costs, relative to the volume of energy they consume, tends to be much lower than for residential customers with lower load factors. Since in most jurisdictions, demand-related capacity costs are a major contributor to total system costs this means that industrial customers are, on a per-kWh basis, less expensive to serve than residential customers, typically resulting in industrial customers paying a lower effective rate per kWh consumed.

This ratio of residential to industrial electricity customer costs is of interest because it effectively controls for factors that may drive all customers' electricity costs up (or down) in a given jurisdiction; it indicates in which jurisdictions industrial electricity costs are most competitive relative to residential electricity costs. **In the case of the EEI survey summarized above, in nearly 65 per cent of the jurisdictions surveyed, the ratio of residential to industrial electricity costs was higher than Nova Scotia's, suggesting that nearly two thirds of the jurisdictions surveyed had a cost environment more favourable to industry than Nova Scotia's.**

Following our initial scan of industrial-to-residential cost ratios (based on the EEI survey, Eurostat figures and other sources), Navigant, in consultation with CME-NS, determined that the following jurisdictions merited further investigation: California, Iowa, Pennsylvania, Texas, Ontario, Ireland, and Germany.

After a detailed examination of these eight jurisdictions, Navigant concluded that their more competitive industrial electricity costs may be driven by one or more of the following three factors:

1. **Electricity rates are used as a tool to support a policy of economic development and job growth, as well as to support the global competitiveness of local industry.** For example:
   a. In **Pennsylvania**, PECO offers an economic development tariff that requires customers to demonstrate (via tax filings of employee payroll) specific levels of job increases for each additional MW of load, as well as requiring LEED[ii] certification of new facilities or the development of brownfield sites.[iii]
   b. In **California**, Pacific Gas and Electric Company (PG&E) offers incremental discounts to eligible customers that are located in cities or counties in which the unemployment rate is 125 per cent of the state average.
   c. In **Germany**, large industrial customers receive very steep discounts (up to 99.5 per cent) on a renewable energy surcharge (6.24 Euro ¢/kWh) to protect employment and industry competitiveness.
2. **Utilities offer industrial customers flexible pricing options tied to the provision of system benefits that reduce costs for all customers**. Utilities understand that industrial customers are not a homogenous group and that a "one-size-fits-all" approach fails to capture the value that large industrial customers have to offer the electricity system. This can take the form of optional tariffs, rate riders, and demand response (DR)[iv] programs, all of which allow industrial customers to reduce their effective cost of electricity and benefit all ratepayers by reducing overall system costs. For example:
   a. In **Iowa**, MidAmerican Energy offers industrial customers the options of time-of-use (TOU)[v] pricing (more suitable for lower load factor customers than the standard rate), a foundry-specific interruptible TOU tariff[vi] designed to optimize arc furnace operation to system costs, and three other demand response or interruptible rate riders, each with different levels of risk to the customer and serving different purposes in reducing system costs.
   b. In **California**, PG&E offers four different demand response programs, some intended principally for economic dispatch, others for emergency and reliability dispatch.[vii] These programs run from the very low-risk (e.g., bill protection for the first year, nominated firm loads) to the much higher risk (e.g., non-compliance results in fines of up to $14/kW), and are intended to provide opportunities for all industrial customers to provide value to the electricity system.
   c. In Ireland, EirGrid, the system and market operator, offers four different demand response programs to large industrial customers, including the opportunity for customers to bid into the capacity market, a short-term auto DR program,[vii] and a more traditional large industrial DR program.

[ii] Leadership in Energy and Environmental Design (LEED) is a building rating system developed by the U.S. Green Building Council.
[iii] Sites previously used for industrial purposes that may be contaminated by low levels of hazardous waste. Development of these sites requires soil remediation, which can significantly increase costs.
[iv] Demand response, or DR, refers to the practice of reducing total system load at peak times by curtailing (shutting down) customers with large loads.
[v] Time-of-use electricity rates are rates that vary by time of day. For example, customers may be subject to one demand charge ($/kW) from 8am to 8pm on non-holiday weekdays (a "peak" period) and another, much lower, charge for demand occurring from 8pm to 8am or on weekends and holidays.
[vi] An interruptible tariff or rate is analogous to a DR program – typically customers exchange the right of the utility to interrupt service for a reduction in rates.
[vii] "Economic dispatch"refers to the practice of using DR resources when the marginal cost of generation exceeds that of using the DR resource.
[vii] "Auto DR" refers to a demand response program in which the participant (an industrial customer) allows the utility or system operator to automatically interrupt that customer's load without warning.

3. **Base electricity rates tend to reflect more closely the costs that customers contribute to the system, in particular the demand driven costs**. Demand driven costs (e.g., generation capacity) generally make up a high percentage of total electricity supply costs. In general, an industrial customer's average consumption relative to its peak demand is high, compared to other classes of customers. This means that on a per kWh basis, industrial customers cost less to serve than the other customer types. In jurisdictions where system costs are more precisely attributed to different classes of customers (i.e. demand driven costs are attributed on the basis of contribution to system peak demands), this is generally reflected in a lower average per kWh cost for industrial customers. For example:
   a. In **Pennsylvania**, industrial customers purchasing their electricity directly from their utility (as opposed to from a competitive supplier) pay a commodity[ix] demand charge that is solely determined by their contribution to overall system peak. A customer's peak demand charge is based entirely on that customer's load in the peak hour of the top five system demand days.
   b. In **California**, customers electing to receive their supply at transmission voltage receive a substantial discount on commodity and distribution and transmission charges, up to $4/kW (~15 per cent) for commodity demand charges and up to $12/kW (~80 per cent) for distribution and transmission demand charges.
   c. In **Ontario**, Class A customers (those with peak demands greater than 5 MW) pay for the Global Adjustment component of their commodity demand charge based on their demand in the peak hour of the top five demand days experienced by the Ontario electricity system.

In conducting the detailed examination of the jurisdictions of interest that yielded the findings above, Navigant's focus was on industrial electricity cost drivers, and not exclusively electricity rates. In Germany, for example, the difference between the taxes charged to industrial and residential customers for the electricity that they consume is a significant driver of the differential between industrial and residential electricity costs.

It is important, in the context of the findings above, to note that NSPI does currently offer an interruptible an interruptible rider for its largest industrial customers (2,000 kVA or 1,800 kW and up). This rider provides a discount of approximately 25 per cent per kVA per month for the nominated interruptible demand (the difference between contracted firm and total billing demand) and a discount of approximately 5 per cent on energy charges. Participants are required curtail the required load within ten minutes of interruption event initiation and are subject to penalties of between $15 to $30 per kVA of required load not curtailed.

NSPI also offers an optional real-time pricing tariff. Under this tariff customers are charged NSPI's actual hourly marginal costs, plus a volumetric (per kWh) adder of between 8 and 11 cents (depending on voltage) during the 16 hours between 7am and 11pm on weekdays, and between 0.6 and 3 cents in all other hours.

In the report that follows, each chapter focuses on a different jurisdiction, providing a summary table of standard rates, optional alternative rates, and load retention and attraction tariffs for between one and three utilities operating in that jurisdiction. This summary table is then followed by a more detailed description of the most relevant aspects. It is important to note that this summary table is not intended to be a comprehensive listing of all applicable rates, riders or charges. The purpose of the more detailed examination of rate structures was to identify particular components (particularly variable charge components and innovative rate structures) that were judged to be potentially significant contributing factors to the low unit cost of electricity (relative to the cost to residential customers) for industrial customers in that jurisdiction.

The total unit costs by utility or jurisdiction shown in this report (for example in Figure ES-1) were not "built up" from the cost components listed in the detailed jurisdictional tables, but obtained directly from the EEI survey cited above, Eurostat or (in the case of Ontario) from the Ontario Ministry of Energy's Long Term Energy Plan (LTEP).

In Table ES-1, a brief summary of the findings for each entity and/or jurisdiction surveyed is provided. Nova Scotia is also shown in this table, for context. This table indicates:

- whether the surveyed entity or jurisdiction offers customers optional rates or system-driven incentives, to take advantage of industrial customers' flexibility to reduce system costs in a variety of ways;
- whether the surveyed entity or jurisdiction offers economic development rates (also known as load retention or attraction tariffs) that are explicitly designed to increase employment or protect the competitiveness of energy-intensive industries;
- whether the surveyed entity or jurisdiction is deregulated (also known as "Open Access" in the U.S.), meaning that customers have many options for contracting energy supply, resulting in commodity prices that closely reflect (or are identical to) wholesale electricity prices; and,
- the average ratio of residential unit electricity cost to industrial unit electricity cost.

[ix] *I.e., the generation cost of electricity, distinct from transmission and distribution charges.*

Table ES-1. Summary of Surveyed Entities and Jurisdictions

Entity Name	Jurisdiction	Optional rates or System-Driven Incentives	Economic Development Rates	Competitive Energy Suply	Average Res : Ind. Ratio
Pacific GAs and Electric (PG&E)	California	✓	✓		2.3
Southern California Edison (SCE)	California	✓	✓		2.4
MidAmerican Energy — South System	Iowa	✓	✓		2.2
Interstate Power and Light (IPL)	Iowa	✓	✓		2.1
Duquesne Light Company	Pennsylvania	✓		✓	1.9
Pennsylvania Electtric Company (PECO)	Pennsylvania	✓	✓	✓	1.6**
PJM Interconections	13 states and D.C.	✓		✓	2.0
Entergy Texas	Texas	✓			2.0
N/A	Ontario	✓	✓		2.0
N/A	Ireland	✓	✓	✓	2.0
N/A	Germany		✓		2.4
Noiva Scotia Power Inc.*	Nova Scotia	✓	✓		1.4

** NSPI offers large industrial customers an Interruptible Rider that offers a discount as an incentive to participationand also offers and optional real-time rate. NSPI does offer a load retention tariff but it s tariff book does not specify the discount offered or to how many customers it may be offered.*

*** Average of all utilities surveyed by EEI located in states in which PJM has a presence*

Source: Navigant analysis

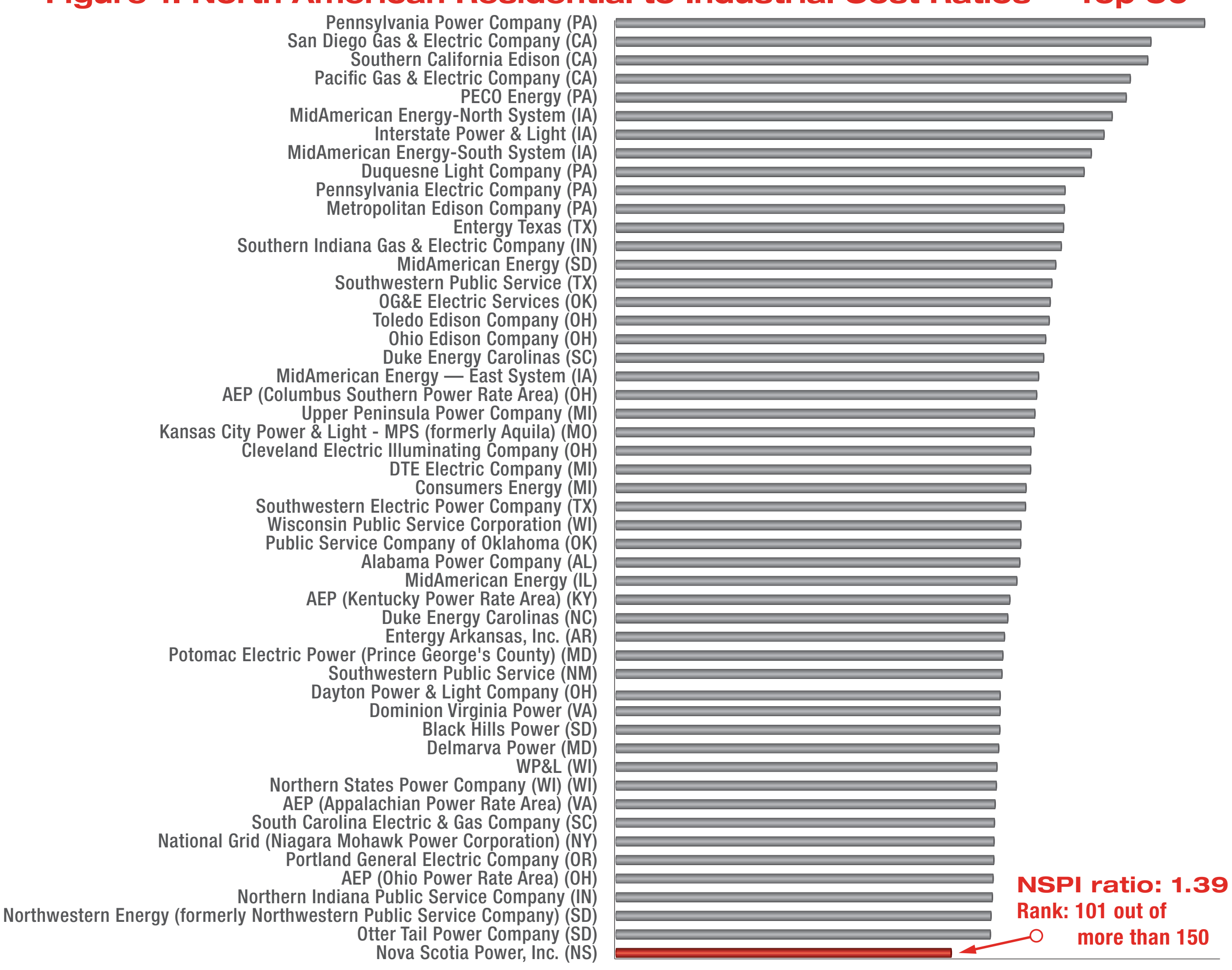
2. INTRODUCTION

Canadian Manufacturers and Exporters, Nova Scotia (CME-NS) engaged Navigant Consulting, Ltd. (Navigant) to survey a number of jurisdictions in North America and Europe to help the CME better understand how "standard" industrial rates compare to residential rates in those jurisdictions, the prevalence and design of load attraction or retention tariffs, and the prevalence and design of other programs or incentives that work to lower the effective cost of electricity for industrial customers.

Navigant undertook this survey in two phases. In the first phase, Navigant conducted a high-level survey of the ratio of residential to industrial electricity costs in the majority of North American and European jurisdictions to determine in which jurisdictions industrial rates, relative to residential rates, were lowest. This ratio is of interest because it effectively controls for factors that may drive all customers' electricity costs up (or down) in a given jurisdiction—it indicates in which jurisdictions industrial electricity costs are most competitive relative to residential electricity costs. The results of this survey, and the anticipated availability of English-language documentation, then determined which eight of these jurisdictions merited a more detailed examination.

Any discussion of electricity rates and rate design must inevitably involve some industry-specific nomenclature, or jargon. To help readers that may not be familiar with some of these words or concepts, we have included a glossary at the end of this report. Words appearing in the glossary will be indicated (the first time they appear) by an asterisk (*).

Figure 1. North American Residential to Industrial Cost Ratios — Top 50



Source: Edison Electric Institute

2.1 Jurisdiction Selection

Figure 1 shows the 50 highest residential-to-industrial ratios for North American jurisdictions (as tracked by the Edison Electric Institute [EEI][x]), i.e., the 50 jurisdictions in which industrial electricity is least expensive, relative to the cost of residential electricity. The EEI produces a semi-annual report estimating the average total cost of electricity for a variety of customer types. Each ratio presented in Figure 1 is the average of the ratio of residential cost per kWh (assuming 1,000 kWh/month consumption) to industrial cost per kWh for a number of different industrial customer sizes. For comparison purposes, the Nova Scotia Power, Inc. (NSPI), ratio is also shown in this figure.[xi]

The EEI survey does not include industrial or residential costs from Ontario. Based on Navigant's analysis of the Ontario Long-Term Energy Plan (LTEP),[xii] this ratio is approximately 2.0. This would place it in eighth position in the chart above, between Interstate Power and Light (IPL) (2.02) and MidAmerican Energy South System (1.97).

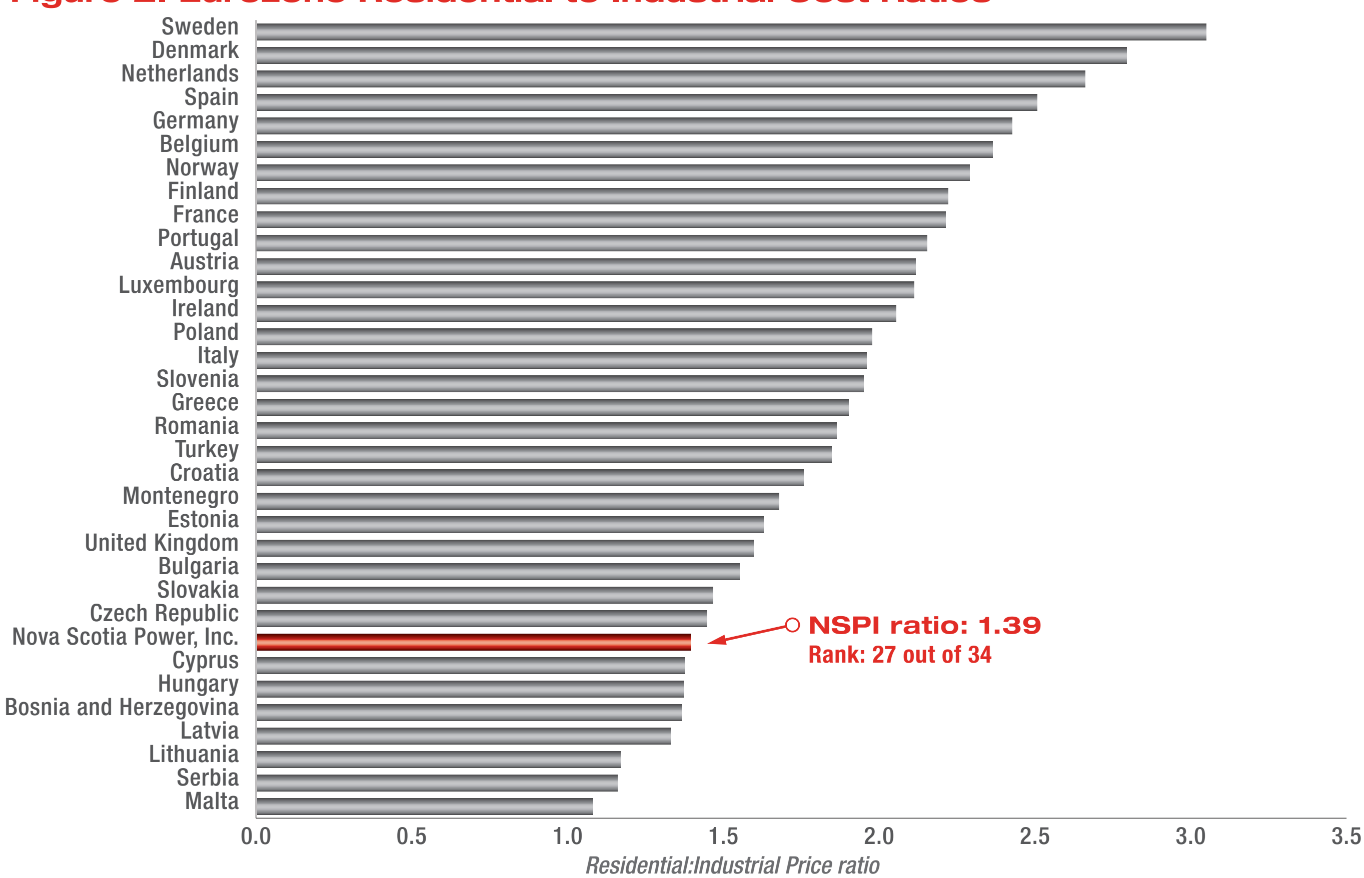
Based on the results above, Navigant, in consultation with the CME, determined that the most relevant North American jurisdictions for future investigation should be California, IowaPennsylvania, Texas, and Ontario.

In Figure 2, Navigant compares the ratio of average residential and industrial electricity costs for electricity in the 35 Eurozone jurisdictions for which Eurostat (the statistical office of the European Commission) has data with the ratio of residential to industrial electricity costs for NSPI (drawn from the EEI survey cited above). The Eurozone ratios shown below are based on the cost to customers inclusive of all taxes and levies. Note that the EEI data do not include any taxes that do not flow through to utility revenues. When ratios are calculated based on costs absent all taxes and levies, NSPI's ratio rank climbs from 27 to 21 out of 34.

Based on the results above and some initial investigation to determine the availability of English-language information and resources, Navigant, in consultation with the CME, determined that the jurisdictions for further investigation should be Ireland and Germany.

Figure 2. Eurozone Residential to Industrial Cost Ratios

Source: Eurostat



[x] *Edison Electric Institute, Typical Bills and Average Rates Report, Winter 2014.*

[xi] *Note that the Edison Electric Institute (EEI) report from which these figures are drawn provide costs for over 150 utilities. Only the 50 utilities with the highest ratios, and NSPI, were included on this graph for reasons of legibility. Had all utilities been shown on this chart, NSPI would appear approximately in the bottom third.*

[xii] *Ontario Ministry of Energy, Achieving Balance: Ontario's Long-Term Energy Plan, November 2013, http://www.energy.gov.on.ca/en/ltep/#.U6LnPPIdU8Q.*

2.2 Structure of this Report

Following this introduction, each chapter of this report will provide additional detail for each of the selected jurisdictions. Each chapter begins with a brief description of average annual energy generation by source fuel, and some discussion of the installed capacity of non-hydro renewables.

This is followed by a table that provides a high-level summary of one or more utilities' rates and programs in that jurisdiction, including (for example) the ratio of residential-to-industrial electricity cost, the "standard" industrial rate(s), a list of alternative rates and system-driven incentives available to customers, and a list of load retention and load attraction tariffs (if such exist). This summary table is then followed by a more detailed description of the most relevant aspects.

It is important to note that this summary table is not intended to be a comprehensive listing of all applicable rates, riders or charges. The purpose of the more detailed examination of rate structures was to identify particular components (particularly variable charge components and innovative rate structures) that were judged to be potentially significant contributing factors to the low unit cost of electricity (relative to the cost to residential customers) for industrial customers in that jurisdiction.

The total unit costs by utility or jurisdiction shown in this report (for example in Figure ES-1) were not "built up" from the cost components listed in the detailed jurisdictional tables, but obtained directly from the EEI survey cited above, Eurostat or (in the case of Ontario) from the Ontario Ministry of Energy's Long Term Energy Plan (LTEP).

Following the final jurisdictional chapter, the most significant jurisdictional findings and trends are summarized in a conclusion.

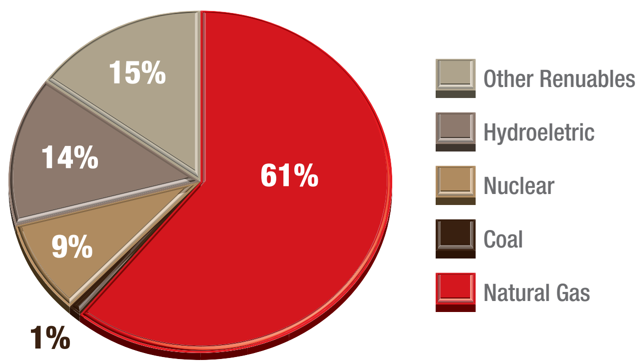
3. CALIFORNIA

Although nearly a third of California's installed generating capacity is from non-hydro renewable generation, this form of generation only supplies one sixth of the average energy consumption to the state (see Figure 3).

Navigant has completed a detailed examination of two of California's largest investor-owned utilities (IOUs), PG&E and SCE. Each of these utilities' industrial rates, and optional and load retention/attraction tariffs are discussed in the two subsections below.

Table 1 reproduces the part of the Table ES-1 relevant to California, summarizing certain key features of the entities reviewed as part of this survey.

Figure 3. California's Energy Generation Mix, 2012



Source: U.S. Energy Information Administration

Table 1. Summary of California Entities

Entity Name	Jurisdiction	Optional rates or System-Driven Incentives	Economic Development Rates	Competitive Energy Suply	Average Res : Ind. Ratio
Pacific GAs and Electric (PG&E)	California	✓	✓		2.3
Southern California Edison (SCE)	California	✓	✓		2.4
Source: Navigant analysis					

3.1 Pacific Gas and Electric

PG&E is the largest of the California utilities, in both surface area and in number of customers. PG&E's service territory extends from just south of the border with Oregon to approximately 100 miles north of Los Angeles. In that territory, PG&E serves over five million customers. Of the utilities included in the EEI study, PG&E's residential to industrial ratio of average cost of electricity is the fifth highest.

This section is divided into the following subsections:

- Industrial Rate Summary Table
- Standard Rates and Voltage Discounts
- Alternative Rates and System-Driven Incentives
- Load Retention and Load Attraction Tariffs

Industrial Rate Summary Table

A high-level summary of Navigant's findings for PG&E are shown in Table 2.

Table 2. Summary of PG&E Industrial Rates

Pacific Gas & Electric Company (CA)						
Average Cost of Electricity (EEI "Typical Bill")						
	Residential	**Industrial**				
Peak Monthly kW:	N/A	1,000	1,000	50,000	50,000	50,000
Load Factor:	N/A	55%	89%	41%	68%	89%
Total unit cost ($/kWh):	$0.251	$0.145	$0.123	$0.118	$0.084	$0.095
Res/Ind Ratio	1.00	1.74	2.04	2.13	3.00	2.65
Standard Rates						
Medium General Demand-Metered TOU* Service (E-19) (500–999 kW)						
Rates vary by time of day and season. Three periods (Peak, Part-Peak, and Off-Peak) in summer, two periods (Part-Peak and Off-Peak) in winter. Summer Peak: noon–6pm, non-holiday weekdays. Off-Peak: 9:30pm–8:30am on non-holiday weekdays and all weekends and holidays. Summer Part-Peak: all other times. Winter Part-Peak: 8:30am to 9:30pm. Summer runs May 1 through October 31.						
Commodity*:	Demand charges of between $13 and $16/kW during summer Peak and between $2.50 and $4 during summer Part-Peak. No charge other periods. Charges vary by customer voltage. Energy charges apply in all periods and vary between ¢5.1/kWh (Summer Off-Peak, Transmission Voltage) and ¢13.8/kWh (Summer Peak, Secondary Voltage).					
Distribution*:	Demand charges of between $1.50 and $8 per kW (all periods), depending on voltage. Additional demand charges of between $0 (all TOU periods, Transmission Voltage) and $5 (summer Peak, Secondary Voltage) by TOU period. No energy charge.					
Transmission*:	Demand charge of $4.50 kW, all voltage levels.					
Large Customers (E-20) (>= 1,000 kW)						
Rates vary by time of day and season as above.						
Commodity:	Demand charges of between $12 and $16/kW during summer Peak and between $2.50 and $4 during summer Part-Peak. No charge other periods. Charges vary by customer voltage. Energy charges apply in all periods and vary between 4.9 ¢/kWh (Summer Off-Peak, Transmission Voltage) and 12.5 ¢/kWh (Summer Peak, Secondary Voltage).					
Distribution:	Demand charges across all periods of between $0.14 (Transmission voltage) and $8 per kW (Secondary Voltage). Additional demand charges of between $0 (all TOU periods, Transmission Voltage) and $5 (summer Peak, Secondary Voltage) by TOU period. No energy charge.					
Transmission:	Demand charge of $4.50 kW, all voltage levels.					
Alternative Rates & System-Driven Incentives						
Peak Day Pricing (PDP):	Credit of $6/kW curtailed, $1.2/kWh charge for event usage. Bill protection for 1 year, firm capacity option avail., 2pm day-ahead notification.					
Base Interruptible Program (BIP):	Incentive of $8-$9/kW curtailed per month. Thirty min. notification. Year round.					
Scheduled Load Reduction Program (SLRP):	Incentive of $0.10/kWh per month of energy curtailed in nominated period.					
Automated Demand Response (ADR):	Incentive of $125–$400 per kW (up to cost of system) to install energy management systems to enable auto-DR*.					
Demand Bidding Program (E-DBP)	Participants receive day-ahead notification and may submit offers of demand reduction to PG&E. PG&E will accept all offers and pay an incentive of $0.5/kWh of realized DR*, provided it is more than 50% of the nominated amount. Payments are capped at 150% of nominated amount.					
Capacity Bidding Program:	Participation only through an aggregator*. Aggregator incentives of between $2 and $25/kW depending on month and performance.					
Load Retention/Attraction Tariffs						
Economic Development Rate: Subject to approval of GO-Biz, an E-19 or E-20 customer signing an affidavit indicating that "but for" receiving the discount that customer would close may receive a 12% discount on charges for 5 years. A customer located in a county or city with an unemployment rate of more than 125% the state average may receive a discount of 30%.						

Standard Rates and Voltage Discounts

While Californian industrial electricity rates appear quite high in absolute terms, relative to those that apply to an average residential customer consuming 1,000 kWh a month, they are very low. For example, residential customers on the standard tariff, that are consuming electricity in the most expensive block,[xiii] pay a bundled* price of ¢36/kWh. A residential customer subject to PG&E's voluntary time-of-use (TOU) tariff can pay a bundled price of as much as ¢52/kWh for electricity.

The two principal rate tariffs relevant for this study are E-19 (Medium Demand-Metered TOU Service) and E-20 (Service to Customers with Maximum Demands of 1,000 kW or More).

For billing purposes PG&E applies three summer and two winter TOU periods; they are defined as shown in Table 3.

Table 3. PG&E TOU Periods

Period	Summer	Winter
Peak	Noon to 6 p.m. , non-holiday weekdays.	N/A
Part-Peak	8:30 a.m. to noon and 6pm to 9:30 p.m., non-holiday weekdays	8:30 a.m. to 9:30 p.m., non-holiday weekdays
Off-Peak	All remaining hours.	All remaining hours.
Source: PG&E		

Customers subject to tariff E-20 (customers with a peak demand of more than 1,000 kW) are subject to a demand charge for peak demand during the Peak and Part-Peak periods, as well as for peak demand overall during the entire month. In addition to varying by time and season, these demand charges vary by customer voltage level. These bundled demand charges are summarized Table 4.

Table 4. PG&E Rate E-20 Demand Charges ($/kW)

Season	Time Period	Secondary Voltage	Primary Voltage	Transmission Voltage
Summer	Peak	$ 17.22	$ 16.86	$ 15.98
	Part-Peak	$ 3.73	$ 3.49	$ 3.46
	All Times	$ 12.28	$ 9.97	$ 4.77
Winter	Part-Peak	$ 0.23	$ 0.25	$0.00
	All Times	$ 12.28	$ 9.97	$ 4.77
Source: PG&E				

There is a significant discount for the "All Times" peak demand charge, depending on customer voltage. If a given customer has an identical peak demand in all three summer periods, that customer will pay nearly 30 per cent less per kW (considering Peak, Part-Peak, and All Times charges together) for receiving electricity at Transmission instead of Secondary voltage. This discount is driven by the much lower distribution charges paid by Transmission customers. Unbundled rates may be seen on the original tariff sheet. Transmission voltage customers pay a distribution charge of only ¢14/kW for "All Times" peak demand, and no distribution charge at all for Peak or Part-Peak demand. Secondary Voltage customers, on the other hand, pay $4.48/kW in distribution charges for Peak demand and $7.65/kW for "All Times" demand (included in figures cited in Table 4).

Likewise, Transmission Voltage customers receive a significant discount on energy charges during summer peak periods, although in this case the discount is driven entirely by the commodity charge differential; no distribution charge is levied on energy consumption for any E-20 customer, regardless of their voltage.

Table 5. PG&E Rate E-20 Energy Charges ($/kWh)

Season	Time Period	Secondary Voltage	Primary Voltage	Transmission Voltage
Summer	Peak	$ 0.148	$ 0.148	$ 0.104
	Part-Peak	$ 0.106	$ 0.104	$ 0.086
	All Times	$ 0.077	$ 0.079	$ 0.071
Winter	Part-Peak	$ 0.099	$ 0.099	$ 0.087
	All Times	$ 0.078	$ 0.083	$ 0.075
Source: PG&E				

Alternative Rates and System-Driven Incentives

Navigant has identified six optional rates or programs that PG&E uses to leverage industrial customer flexibility to reduce system costs through incentivized demand reduction. Depending on the program/tariff/rider, customers may participate in more than one of the programs listed below.

Peak Day Pricing (PDP)

All E-19 and E-20 customers are automatically enrolled in the PDP rate, but may opt out at any time. During PDP events, customers must pay an additional $1.20/kWh for all energy consumed during the event, but, conversely receive a credit for $6.37 for each kW of demand they reduce.[xiv] For the first 12 months in which customers are enrolled, they are provided with bill protection, effectively removing any risk to the customer in the first 12 months, to encourage customers to stay in the program.

[xiii] Residential rates are inclining block; they become progressively more expensive as a series of monthly energy level thresholds are crossed.
[xiv] It is not clear from the E-19 or E-20 tariffs whether demand reductions are measured based on some settlement baseline or on the customer's non-PDP peak demand.

Customers that wish to participate, but want to limit their exposure to risk, may nominate a Capacity Reservation Level (CRL). A customer with a CRL will be charged their standard rate for all consumption at or below their CRL on PDP event days. Conversely, however, such customers will be charged for demand at the CRL during summer even if actual demand falls below that level. Customers may change the CRL every 12 months.

PG&E calls between nine and 15 PDP events each year, each event running from 2pm to 6pm. Customers are provided with 24-hour advanced notification of PDP events, and the PG&E website provides a qualitative forecast of PDP event likelihood for the longer time horizon (e.g., as of 6 July, 2014, the forecast for 10 July was "Event Possible" and the forecast for 11 July was "Event Unlikely"). In addition, PG&E indicates a set of very specific conditions that trigger PDP events: non-holiday weekdays with temperatures exceeding 98oF and weekends and holidays with temperatures exceeding 105oF.[xv] Assuming that PG&E calls 12 PDP events per year, this relatively low-risk (for customers) DR program effectively offers a credit incentive to customers of more than $76/kW-year*.

Base Interruptible Program (E-BIP)

The BIP is an optional tariff for E-19 and E-20 customers. Customers may either participate directly or else may appoint an aggregator to act on their behalf.

Participants must nominate a Firm Service Level (FSL) of demand. When BIP events are called, participant demand must be reduced to, or below, FSL demand. Participants receive a monthly incentive payment of:

- $8/kW for each kW of Potential Load Reduction (PLR) below 500 kW
- $8.5/kW for each kW of PLR between 500 and 1,000 kW;
- $9/kW for each kW of PLR over 1,000 kW

Where PLR is the difference between a customer's average Peak period demand and their FSL (summer) or their average Part-Peak period demand and their FSL (winter). On an annual basis, this indicates a value to PG&E of capacity from this program of between $96 and $108/kW-year.

Penalty payments are severe; customers are charged $6/kWh for all energy consumption above their FSL during events.

PG&E must give participants a minimum of 30 minutes' notice prior to an event, may call no more than one event per day, ten events per month or 180 hours of events per year. Events may last as long as four hours.

Directly enrolled customers (i.e., customers not enrolled through an aggregator) may elect to participate in PG&E's "Underfrequency Relay Program". This program allows PG&E to automatically interrupt service via an underfrequency relay device.

Scheduled Load Reduction Program (E-SLRP)

The E-SLRP is an optional tariff intended to reduce summer load during periods in which system peak conditions are frequently observed.

Each day of the week (Monday through Friday) is divided into three periods, 8am to noon, noon to 4pm, and 4pm to 8pm. There are, therefore, 15 potential SLRP periods in each week. Participants may choose up to three, but no more than two may be for the same time period.

Every week, between June 1 and September 30, participants must reduce consumption in their chosen periods by at least 15 per cent. Participants are not permitted to shift load to adjacent periods that are also SLRP periods (e.g., a customer may not reduce consumption between 8am and noon by 15 per cent and compensate by increasing consumption between noon and 4pm).

Participants are paid an incentive of ¢10/kWh for all energy curtailed during their nominated SLRP periods. Settlement is calculated based on the participant's consumption in the non-SLRP periods of the ten days immediately preceding the event day. The only penalty for not achieving nominated load reductions is possible ejection from the program, making this effectively a no-risk program for customers.

This program is capped at the current level of enrolled MW, but a waiting list is maintained by PGE.

Automated Demand Response (ADR)

The ADR program does not provide direct incentives for demand response, but rather provides incentives for customers to invest in control technologies that allow them to automate demand response and thus respond more efficiently to PDP or other demand response programs. Depending on the degree of automation, and the energy end use to which it is applied, customers may earn incentives of between $125 and $400/kW per kW controlled, up to the total cost of the control technology.

Demand Bidding Program (E-DBP)

The E-DBP schedule is a flexible, low-risk DR program that allows participants to opt in to individual curtailment events. Following day-ahead notification at noon, participants may make offers of quantities of DR to PG&E until 3pm. Following settlement evaluation of event impacts, participants will receive a bill credit of $0.50 per kWh curtailed. No incentive credit is paid if actual DR impacts are less than 50 per cent of nominated load, and credits are capped at 150 per cent of

[xv] PG&E may modify these thresholds once per month.

nominated load. In 2013, PG&E called six events, each lasting eight hours, implying that PG&E values capacity delivered by this program at approximately $24/kW-year. This program carries no financial penalty for customers not achieving nominated curtailment, making it a no-risk program for customers.

Settlement is calculated using a ten-day baseline. If the participant chooses, PG&E may also use a day-of adjustment for calculating the baseline.[xvi]

Events are triggered when CAISO's[xvii] day-ahead load forecast exceeds 43 GW, CAISO issues an Alert notice, temperatures exceed a set threshold specified by the PG&E website, and PG&E forecasts adequacy issues.

Capacity Bidding Program (E-CBP)

CBP is a voluntary demand response program, but one in which customers may only participate via an aggregator*. Customers may subscribe to a day-ahead option (notification by 3pm, day-ahead) or a day-of option (minimum of three hours notification prior to event). Within each option, three "products" are available: customers may elect to be available for events:

- One to four hours in length
- Two to six hours in length
- Four to eight hours in length

Payments to the aggregator are based on an option (day-ahead or day-of) and product-specific capacity price that varies by month, from $2.17/kW (October, day-ahead, 1–4 hours) to $24.81/kW (August, day-of, 6–8 hours). This capacity price is multiplied by a factor that itself is based on the ratio of delivered to nominated curtailment capacity. The possible values of this factor are shown in Table 6.

Table 6. CBP Capacity Price Adjustment Factor

Capacity Ratio (Delivered/Nominated)	Capacity Price Adjustment
≥ 105 %	1.05
75 %–105 %	Capacity Ratio
60 %–75 %	0.5
0 %–60 %	- (0.6 — Capacity Ratio)
< 0 %	-0.6
Source: PG&E	

Note, for example, that the upper limit of the capacity for which an aggregator may receive credit is 105 per cent of the nominated load, and that should the aggregator deliver less than 60 per cent of the nominated curtailment, the aggregator will be subject to penalty payments.

In Program Year 2013 (PY2013), PG&E called only five events for both day-ahead and day-of options. Assuming that three of these occurred in August (when capacity is most often required) and one each was called for July and September, this implies that PG&E values capacity obtained from this program at approximately $100/kW-year. The other California IOUs called more than five events for this program—in 2013, SCE called its day-ahead option participants 28 times.

Load Retention and Load Attraction Tariffs

PG&E offers one load retention tariff, the Economic Development Rate (EDR) schedule. This schedule offers a discount to customers with loads over 200 kW that would, absent the tariff, cease operations in California. Applicants for the discount must sign an affidavit attesting to the fact that, but for the EDR incentive rate, the customer will not retain load or remain in operation in California, and must be approved by the California Governor's Office of Business and Economic Development (GO-Biz).

Customers approved by GO-Biz receive a five-year discount of 12 per cent from their standard (before-tax) tariff charges. Customers located in a county or city with an annual unemployment rate more than 1.25 times the state average will receive a five-year discount of 30 per cent.

Enrollment for this discount is limited to 200 MW of aggregate customer demand.

3.2 Southern California Edison

SCE serves the second-largest geographic area in California Its service territory (approximately 50,000 square miles) extends in the rough shape of a triangle toward the Nevada and Arizona borders, with its point on the Los Angeles basin. SCE serves a territory with a population of approximately 14 million people, 280,000 small businesses, and 5,000 large businesses. Of the utilities included in the EEI study, SCE's residential to industrial ratio of average cost of electricity is the fourth highest.

This section is divided into the following subsections:

- Industrial Rate Summary Table
- Standard Rates and Voltage Discounts
- Alternative Rates and System-Driven Incentives
- Load Retention and Load Attraction Tariffs

Industrial Rate Summary Table

A high-level summary of Navigant's findings for SCE are shown in Table 7.

[xvi] Navigant has on a number of occasions evaluated the accuracy of different types of DR baseline. In every case, the single most important contributor to baseline accuracy was the use of a day-of adjustment.
[xvii] California Independent System Operator (CAISO).

Table 7. Summary of SCE Industrial Rates

Southern California Edison (CA)						
Average Cost of Electricity (EEI "Typical Bill")						
	Residential	**Industrial**				
Peak Monthly kW:	N/A	1,000	1,000	50,000	50,000	50,000
Load Factor:	N/A	55%	89%	41%	68%	89%
Total unit cost ($/kWh):	$0.238	$0.131	$0.107	$0.103	$0.087	$0.081
Res/Ind Ratio	1.00	1.81	2.21	2.31	2.74	2.93
Standard Rates						
Time-of-Use - General Service — Large (Option B) (TOU-8) (>=500 kW)						
Rates vary by time of day and season. Three periods (Peak, Part-Peak, and Off-Peak) in summer, two periods (Part-Peak and Off-Peak) in winter. Summer Peak: noon–6pm, non-holiday weekdays. Off-Peak: 9:30pm–8:30am on non-holiday weekdays and all weekends and holidays. Summer Part-Peak: all other times. Winter Part-Peak: 8:30am to 9:30pm. Summer runs May 1 through October 31.						
Commodity:	Demand charges of between $21 and $26/kW during summer Peak and between $5 and $7 during summer Mid-Peak. No charge other periods. Charges vary by customer voltage. Energy charges apply in all periods and vary between ¢3.7/kWh (Summer Off-Peak, > 50 kV) and ¢12.7/kWh (Summer Peak, <2 kV).					
Distribution*:	Demand charge of between $0 and $11.50 per kW, depending on voltage. Energy charge of between ¢0.2 and 0.3/kWh depending on voltage.					
Transmission*:	Demand charge of ~ $3 kW, all voltage levels. Energy charge of 0.4 ¢/kWh					
Alternative Rates & System-Driven Incentives						
Critical Peak Pricing (CPP)*:	Credit of $12/kW curtailed, $1.3/kWh charge for event usage. Bill protection for 1 year, firm capacity option avail, 3pm day-ahead notification.					
Option A:	Participants of Permanent Load Shifting (PLS) program eligible for this option. Identical to Option B (standard rate) except that commodity demand charge eliminated. PLS program requires participants to reduce peak demand by at least 15% using some form of energy storage.					
Real Time Pricing (RTP)*:	Identical to standard rate, but commodity demand charge replaced by 24 hourly energy prices for five summer weekday types (defined by temperature) and two winter weekday types and two weekend day types ("low cost" vs "high cost"). Energy cost fluctuates between ¢2/kWh and $4.1/kWh.					
Other programs available include DBP, CBP, and SLRP, similar to those offered by PG&E.						
Load Retention/Attraction Tariffs						
Economic Development Rate — Attraction (EDR-A): New loads of > 200 kW that but for the EDR discount would locate in a another jurisdiction, for which estimated electricity costs are more than 5% of non-raw-material costs may receive a discounted rate. Customers with estimated electricity costs that are >15% of non-raw-material costs will be provided expedited screening.						
Economic Development Rate — Expansion: Functionally identical to EDR-A but applicable to new loads > 200 kW for existing customers.						
Economic Development Rate — Retention: Functionally identical to EDR-A but applicable to loads > 200 kW that would (without this rate) relocate from SCE's service territory.						

Standard Rates and Voltage Discounts

As is the case for PG&E, SCE's industrial rates appear high; however, residential customers on the standard tariff may pay as much as ¢35/kWh for consumption in the highest price block.

The standard rate for large customers (> 500 kW) in SCE service territory is the TOU-8 General Service tariff, Option B. As with PG&E, SCE divides all summer hours into three TOU periods (On-Peak, Mid-Peak, and Off-Peak) and all winter hours into two TOU periods (Mid-Peak and Off-Peak). SCE's Mid-Peak starts 30 minutes earlier than PG&E's Part-Peak (at 8am instead of 8:30) and also ends 30 minutes earlier (at 9pm instead of 9:30).

The demand charges by the time period to which they apply for TOU-8 (Option B) customers are shown below in Table 8. Note that as with PG&E's charges, these are additive.

Table 8. SCE Rate TOU-8 (Option B) Demand Charges ($/kW)

Season	Time Period	<2kV	2kV–50kV	50kV-220kV	220kV
Summer	On-Peak	$ 25.33	$ 26.19	$ 21.70	$ 21.54
	Mid-Peak	$ 7.16	$ 7.22	$ 5.79	$ 5.63
	All Times	$ 14.99	$ 14.32	$ 6.18	$ 3.32
Winter	Mid-Peak	$ 0.00	$ 0.00	$0.00	$0.00
	All Times	$ 14.99	$ 14.32	$ 6.18	$ 3.32
Source: SCE					

As was the case for PG&E, there is a substantial discount for higher voltage customers, with 220 kV customers paying nearly 80 per cent less than customers with < 2 kV voltage for the "All Times" demand charge. The "All Times" demand charge is the sum of the transmission and distribution (T&D) demand charges.

In addition, the highest voltage customers also receive a discount to generation charges during the On-Peak period of approximately 15 per cent, compared to lower voltage customers.

Table 9 shows the energy charges for a TOU-8 (Option B) customer. As may clearly be seen, although higher voltage customers still receive a discount compared to lower voltage customers, it is not nearly so substantial as for the demand charge. Note that the voltage discount that applies to the demand charges is predominantly driven by a facilities-related distribution charge, whereas it is the commodity cost of energy, rather than transmission or distribution cost, that is most driving the energy discount.

Table 9. SCE Rate TOU-8 (Option B) Energy Charges ($/kWh)

Season	Time Period	<2kV	2kV–50kV	50kV-220kV	220kV
Summer	On-Peak	$ 0.153	$ 0.148	$ 0.127	$ 0.127
	Mid-Peak	$ 0.093	$ 0.088	$ 0.080	$ 0.080
	All Times	$ 0.065	$ 0.062	$ 0.058	$ 0.057
Winter	Mid-Peak	$ 0.094	$ 0.090	$ 0.084	$ 0.083
	All Times	$ 0.071	$ 0.068	$ 0.064	$ 0.063

Source: SCE

Alternative Rates and System-Driven Incentives

Navigant has identified six optional rates or programs that SCE uses to leverage industrial customer flexibility to reduce system costs through incentivized demand reduction. Three of these are very similar to PG&E's Demand Bidding Program, Capacity Bidding Program, and Scheduled Load Reduction Program, and share the same names, and therefore will not be described in this section.

Critical Peak Pricing (CPP)

This program is very similar to PG&E's PDP rate option. As with PDP, this is a default enrollment program from which customers must choose to opt out. (The "other applicable tariff" for customers that opt out is Option B, described above.)

CPP participants may receive a bill credit of up to $12/kW curtailed,[xviii] but must pay between $1.29/kWh (> 50 kV customers) and $1.37/kWh (< 2kV customers) for all energy consumption during a CPP event.

Participants receive bill protection for their first 12 months in the program and may nominate a Capacity Reservation Level (CRL) that is not subject to CPP event charges or credits. Unlike PG&E, nominating a CRL does not set a minimum summer demand charge that the given customer must pay; it only limits the customer's risk and opportunity to earn credit.

SCE will only call events on non-holiday weekdays. Events may be called when the downtown Los Angeles temperature is above 90oF by 2pm, CAISO issues an Alert, or day-ahead load and price forecasts justify it. SCE will call 12 CPP events per year.

At 12 events per year, this relatively low-risk (for customers) DR program effectively offers a credit incentive to customers of more than $144/kW-year.

TOU-8 (Option A)

Option A of the TOU-8 tariff (i.e., the standard large general service tariff) is available only to customers participating in SCE's Permanent Load Shifting (PLS) program. To qualify for and participate in the PLS program, a customer must shift energy consumption on an ongoing (i.e., permanent) basis away from SCE's summer On-Peak period (noon to 6pm) through the use of some form of storage technology. Qualifying technologies include thermal energy storage, solar batteries, pumped storage, and any other technology approved by SCE.

Installed PLS systems must be sufficient to accommodate at least 15 per cent of the customer's annual peak demand from the previous 12 months.

The rates for Option A are identical to those of Option B, except that the commodity/generation demand charge is eliminated. The demand charges are therefore equivalent to those shown in Table 8, above, except that the "Summer On-Peak" and "Summer Mid-Peak" rows would contain only zeros. Given the summer period lasts from June 1 through October 1, this suggests that PG&E values demand reductions obtained from this program at approximately $80-$100/kW-year (depending on customer voltage).

General Service – Large Real-Time Pricing (TOU-8 RTP)

This optional tariff's charges are identical to the standard TOU-8 Option B rates except that the On-Peak and Mid-Peak commodity demand charges are replaced by hourly energy charges. There are a total of 216 different possible hourly energy prices for each of the voltage categories defined above,[xix] one price for each of 24 hours on nine different day types.

The nine day types are:

- Extremely Hot Summer Weekday (temperature: ≥ 95oF)
- Very Hot Summer Weekday (temperature: 91–94 oF)
- Hot Summer Weekday (temperature: 85–90 oF)
- Moderate Summer Weekday (temperature: 81–84 oF)
- Mild Summer Weekday (temperature: ≤ 80)
- High-Cost Winter Weekday (temperature: >90oF)

[xviii] Higher voltage customers receive slightly less ($11.60/kW).
[xix] Note that RTP charges are identical for 50 kV–220 kV customers and 220 kV customers.

- Low-Cost Winter Weekday (temperature: ≤ 90 oF)
- High-Cost Weekend (temperature ≥ 78 oF)
- Low-Cost Weekend (temperature < 78 oF)

Costs can vary significantly within these 216 different types of hours, rising to over $4/kWh at 4pm on extremely hot summer weekdays, to falling to just a little over 2 ¢/kWh at 4am on a mild summer day. The complete menu of prices for all voltage types may be found on the TOU-8-RTP tariff sheet.[xx]

Load Retention and Load Attraction Tariffs

SCE offers three relevant tariffs that all are very similar but target different customers. The three tariffs are:

- EDR-A: Economic Development Rate — Attraction
- EDR-E: Economic Development Rate — Expansion
- EDR-R: Economic Development Rate — Retention

The only significant difference between these tariffs is that suggested by their names: the first is intended to attract new load, the second to expand existing loads, and the third to prevent existing loads from decamping to another jurisdiction.

As with the PG&E economic development discount, each of these rates is subject to a program cap of 200 MW of participation. Unlike the PG&E rate, however, no discount rate is specified, only that "the customer's total bill shall be subject to a discount as provided in the customer's EDR agreement.", and that it last for five years only.

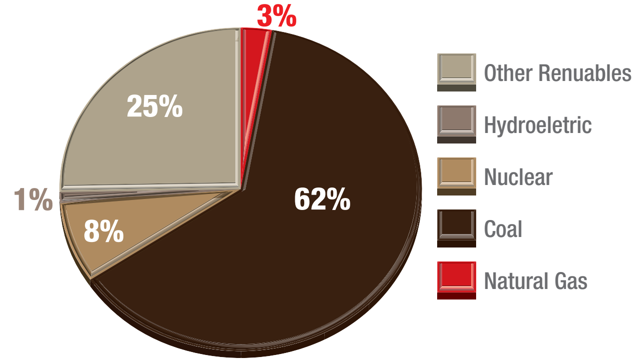
Eligibility criteria are, however, more specifically laid out: customers are only eligible for the EDR discount if estimated electricity costs make up more than 15 per cent of its estimating operating costs (not including the cost of raw materials). As with PG&E's rate, a "but for" signed affidavit is required. Additionally, the approval of the Office of California Business Investment Services (CalBIS) is also required.

4. IOWA

Over a third of Iowa's installed generation capacity is from wind turbines: with more than 5 GW of installed capacity in 2013, it ranks third in the U.S. for total installed wind generating capacity.[xxi] Wind also makes a substantial contribution to Iowa's annual electricity generation, contributing a quarter of all energy generated in the state in 2012 (see, below), and over 27 per cent of energy generated in the state in 2013.[xxi] The remainder of Iowa's electricity is, for the most part, supplied by coal-burning generation.

Navigant has completed a detailed examination of two of Iowa's largest utilities, MidAmerican Energy and Interstate Power and Light (IPL). Within MidAmerican's Iowa service territory there are four systems, one for each cardinal direction. For concision, we have limited our discussion to the "South" system. Each of these utilities' industrial rates, and optional and load retention/attraction tariffs, are discussed in the two subsections below.

Figure 5. Iowa's Energy Generation Mix, 2012



Source: U.S. Energy Information Administration

Table 10 reproduces the part of the Table ES-1 relevant to Iowa, summarizing certain key features of the entities reviewed as part of this survey.

Table 10. Summary of Iowa Entities

Entity Name	Jurisdiction	Optional rates or System-Driven Incentives	Economic Development Rates	Competitive Energy Suply	Average Res : Ind. Ratio
MidAmerican Energy — South System	Iowa	✓	✓		2.2
Interstate Power and Light (IPL)	Iowa	✓	✓		2.1

Source: Navigant analysis

[xx] https://www.sce.com/NR/sc3/tm2/pdf/ce78-12.pdf.
[xxi] American Wind Energy Association, Iowa Wind Energy, http://www.awea.org/Resources/state.aspx?ItemNumber=5224. .

4.1 MidAmerican Energy — South System

MidAmerican Energy is the largest energy company in Iowa, and serves 740,000 customers over a service territory that covers 10,600 square miles of Iowa, Illinois, South Dakota, and Nebraska. Only rates relevant to the Iowa service territory are discussed in this section. Of the utilities included in the EEI study, MidAmerican Energy North's residential to industrial ratio of average cost of electricity is the seventh highest and MidAmerican Energy South's ratio is the ninth highest.

This section of the Iowa chapter is divided into the following subsections:

- Industrial Rate Summary Table
- Standard Rates and Voltage Discounts
- Alternative Rates and System-Driven Incentives
- Load Retention and Load Attraction Tariffs

It is important to note that the rates discussed below for MidAmerican were those in force at the time of writing and that these have since been superseded by a new tariff that became effective as of July 31, 2014. Although the rates introduced in this newer tariff differ from those that were in force when this chapter was drafted, the rate structures remain the same. Tariff sheet names have also changed. In the current MidAmerican tariff, the applicable tariffs would include "Large Electric Service" (LS) and "Substation Service" (SS).

Industrial Rate Summary Table

A high-level summary of Navigant's findings for MidAmerican South is shown in Table 11.

Table 11. Summary of MidAmerican South Industrial Rates

MidAmerican Energy-South System (IA)						
Average Cost of Electricity (EEI "Typical Bill")						
	Residential	Industrial				
kW:	N/A	1,000	1,000	50,000	50,000	50,000
Load Factor:	N/A	55%	89%	41%	68%	89%
$/kWh	$0.098	$0.053	$0.041	$0.059	$0.046	$0.041
Res/Ind Ratio	1.00	1.87	2.40	1.66	2.13	2.42
Standard Rates						
Large General Service, Secondary/Primary Voltage (LLS/LPS and ALS/APS) (>= 200 kW)						
Note: MidAmerican is a vertically integrated utility. Rate tariffs do not show unbundled rates.						
Demand Charge:	Between $6 and $7/kW, depending on season and voltage. Transformer ownership credit of $0.3/kW available to customers that furnish own transformers.					
Energy Charge:	Declining block rate with price thresholds defined by individual customer peak demand. Price is ¢2–4.2/kWh depending on voltage level, season, and customer peak demand.					
Large General Service, Transmission Voltage (LXS and AXS) (>= 2,000 kW)						
Demand Charge:	Declining block rate: $7.20/$4.98 (>= 18 MW, summer/winter) to $7.75/$5.54/kW (< 18MW, summer/winter)/kW					
Energy Charge:	Declining block rate with price thresholds defined by number of hours elapsed in month. Price is ¢2–2.6/kWh depending on voltage level, season, and customer peak demand.					
Alternative Rates & System-Driven Incentives						
Large GS with TOU (LNS/LOS, LVS/ LRS, LXP/LXO)	Optional. Available to customers with primary, secondary or transmission voltage. Peak demand charge decreases as function of magnitude of demand in peak period. Most expensive peak demand charge is ~2x the standard demand charge. Off-Peak is slightly less than standard charge. Customer pays whichever charge (peak or off-peak) is greater. Energy price: ¢1.8-2.4/kWh (off-peak and peak). On-peak period is 9am - 10pm, non-holiday weekdays.					
Curtailment Service (Rider CS):	Credit of $40 (year-to-year contract) - $46 (3-year contract)/kW per year. Thirty-min. notice with 12-hour pre-notice, or 2-hour notice without. Max. six hours curtailment. Max. 16 events per year. Emergency, reliability, and economic dispatch. Specific conditions for reliability and economic dispatch in Rider. Penalty charges cannot exceed annual credits. Customers must curtail down by nominated curtailable load.					
Interruptible Load Replacement Energy Service (Rider ILR)	Interruption via automatic controls – ten-minute notification. Payment is between 101% (transmission or direct substation service) and 107% of MidAmerican's energy purchase price. Available only to customers also participating in Rider CS. NB: This rider is driven by Midwest Reliability Organization (MAPP) and will be terminated if that org. ceases to be responsible for MidAmerican's adequacy resources.					
Large GS, Interruptible Time-of-Use at Primary Voltage for Iron Foundry (LCL)	Available to iron foundry operations of min. 9 MW with arc furnaces with min. 6 MW. Requires customer be able/willing to curtail 30% of load. For economic dispatch, 30-min. notice with 12-hour pre-notice, or 2- hour notice without. For reliability curtailment, MidAmerican will provide as much notice as possible, but may curtail without warning if required. Demand charge: $6–$7/kW with $3/kW for all kW of interrupted load. Declining block rate for energy as per standard rates for on-peak hours, lowest price for off-peak: 2–4 ¢/kWh (varies by TOU and season).					
Short-Term Interruptible Energy Service (Rider 12):	Ad hoc structure — economic dispatch "from time to time", with price, nominated load, and length of interruption to be negotiated prior to each request for interruption.					
Contract Pricing (CJD, CTE)	Company-specific contract (CJD) for Deere & Co. manuf. installation and foundry. Demand charge applies only 9am–9pm; $1–$3/kW shoulder period, $4–$9/kW peak (by season). Energy price ¢1.3-2.3/kWh. High demand/high load factor tariff (CTE) avail. to Neal Industrial Site (Port Neal) customers. Single demand charge — ~$5/kW. Single energy charge — 2 ¢/kWh.					
Load Retention/Attraction Tariffs						
Flexible Pricing (Rider FP): Discounted rates to be offered under this rider to encourage a customer or group of customers to increase or maintain usage. Discounts may be offered only if cost/benefit analysis indicates that there is a net benefit to both MidAmerican and the customer. Discounts offered to a single customer must also be offered to all direct competitors in the same service territory. Discounted price may not be less than the marginal cost of serving the customer.						

Standard Rates and Voltage Discounts

There are two base tariffs offered by MidAmerican South[xxii] that are relevant to the CME's members: the LLS[xxiii] Large General Service tariffs, applicable to customers using either Primary or Secondary voltage, and the LXS Large General Service tariff, applicable to customers using transmission voltage. In the case of the LLS, the minimum demand charge is for 200 kW, and in the case of the LXS tariff it is for 2,000 kW.

In its rate tariffs, MidAmerican does not disaggregate charges in the same manner as the California IOUs and shows only the bundled energy and demand charges.

MidAmerican South demand charges to large industrial customers are summarized by tariff type/voltage level in Table 12 below. Perhaps the most interesting characteristic of these charges is the discount offered to transmission-connected customers for demands over 18 MW — nearly 30 per cent compared to the charge per kW for demand less than 18 MW. Due to the bundled nature of the tariff charges, it is unclear whether this discount is being driven by generation, transmission or delivery charges.

Table 12. Demand Charges ($/kW per month) MidAmerican South Large Industrial Customers

Season	Secondary Voltage	Primary Voltage	Transmission	
			First 18,000 kW	All Additional kW
Summer	$7.07	$6.93	$7.75	$5.54
Winter	$6.31	$6.19	$7.20	$4.98

Source: MidAmerican Energy

In addition to the discount for demand exceeding 18 MW, transmission-connected and primary voltage large industrial customers are eligible for a credit of $0.3/kW for transformer ownership.

MidAmerican's energy charge for large industrial customers is interesting in the manner in which it incentivizes customers to maintain a high load factor. Energy charges are three-tiered, declining block structure – energy consumed costs one price up until a threshold number of kWh, a lower price after that, and a still lower price after a second threshold.

What is particularly interesting is that the thresholds are based on customer's peak monthly demand: the threshold for leaving the first (most expensive) pricing block is (e.g., for transmission-connected customers) 300 hours times the monthly peak demand of the customer. So, for example, a customer with 10,000 kW of monthly peak demand will pay the most expensive charge for energy in a given month until that customer has consumed 3 GWh. The implicit incentive to customers is to maintain as high a load factor as possible.

The energy charges for primary, secondary, and transmission large customers are shown in Table 13.

Table 13. MidAmerican South Energy Charges (¢/kWh)

Season	Energy Tier Threshold (Number of Hours times Monthly kW)	Secondary Voltage	Primary Voltage	Transmission
Summer	250/300*	4.202	4.136	2.597
	100	2.874	2.841	2.243
	400	2.044	2.021	2.044
Winter	250/300*	3.748	3.693	2.597
	100	2.874	2.841	2.243
	400	2.044	2.021	2.044

**300 hours time peak monthly kW for transmission customers, 250 for primary and secondary customers.*

Source: MidAmerican Energy

Most noteworthy about these energy charges is that although transmission customers appear to receive a substantial discount in the first (most expensive) tier, the trajectory of the price decline by tier is much less steep than for primary or secondary voltage customers, with prices roughly equalizing across customer types in the third tier. As above, since MidAmerican tariffs show only the bundled charges, it is impossible to determine what component of system costs is driving this discount.

Alternative Rates and System-Driven Discounts

Navigant has identified six alternative rates offered by MidAmerican to leverage customer flexibility to drive down system costs.

Large General Service with Time-of-Use (LNS/LOS, LVS/LRS, and LXP/LXO)

This set of three optional tariffs provides large customers with a significant incentive to shift consumption to off-peak periods. This set of tariffs is most likely to be most attractive to customers with relatively low load factors for whom most

[xxii] Note that this applies to the tariff that was effective at the time of writing. Since this chapter was drafted a new MidAmerican tariff has become effective (as of July 31, 2014). This new tariff applies uniformly across all of the MidAmerican territories.
[xxiii] Note that in fact there are four different codes that cover customers falling under these tariffs. For simplicity they shall be referred to collectively in the body of this report as LLS customers. All four tariff codes are shown in the summary table. .

energy consumed falls in the first (and most expensive) tier.

Demand charges vary by magnitude of demand and depending on the time of day — there is a Peak and an Off-Peak demand charge. Customers do not pay both, however, but only whichever of the charges is greater, making the optimal strategy in response to this demand charge to maintain a monthly peak demand in each of the two periods that is inversely proportional to the price in those periods.

The demand charges for these tariffs are summarized in Table 14 below.

Table 14. Demand Charges for Optional TOU Rate

Season	TOU Period/ kW Threshold	Secondary Voltage	Primary Voltage	Transmission
Summer	Peak, first 600 kW	$15.17	$14.87	$14.56
	Peak, incremental 10,400 kW	$12.66	$12.41	$12.15
	Peak, all additional kW	$11.24	$11.01	$10.78
	Off-Peak	$6.33	$6.21	$6.08
Winter	Peak, first 600 kW	$13.21	$12.94	$12.68
	Peak, incremental 10,400 kW	$10.72	$10.51	$10.28
	Peak, all additional kW	$9.51	$9.32	$9.13
	Off-Peak	$6.33	$6.21	$6.08
Source: MidAmerican Energy				

Note that the Peak demand charges are approximately twice those paid under the standard rate but that the Off-Peak demand charge is only slightly less ($1/kW or less) than the standard demand charge. In fact, the Off-Peak demand charge is actually higher than the rate charged for transmission-connected customers' demand above 18,000 kW.

The customer benefit of this rate is derived principally from the much lower cost of energy, as shown in Table 15, which shows the energy charges of this optional rate. Note that energy charges under this optional rate do not vary by season.

Table 15. Energy Charges (¢/kWh) for Optional TOU Rate

TOU Period	Secondary Voltage	Primary Voltage	Transmission
Peak	2.409	2.376	2.355
Off-Peak	1.866	1.844	1.834
Source: MidAmerican Energy			

The principal beneficiaries of this optional rate (and thus those likely to participate in it) are large customers with relatively low load factors and a peak demand sufficiently low that a significant proportion of it falls below the 18,000 kW threshold for the transmission-connected standard rate, relatively higher levels of consumption in the summer, and an ability to shift consumption to the Off-Peak period.

Curtailment Service (Rider CS)

This rider is available to large general service customers with an ability to curtail 200 kW or more of demand. Two options are available for participation under this rider: Option A, a three-year contract that provides an annual incentive of $46/nominated curtailable kW, and Option B, a year-to-year contract that provides an annual incentive of $40/nominated curtailable kW.

Participants that fail to curtail their contracted load will be charged a proportionate share of any replacement energy charges levied by the Midwest Independent System Operator (MISO), with the proviso that charges may not exceed the annual curtailable load credit.

Participants may reduce load using standby generation as well as process/production curtailment.

Notification may be provided up to 30 minutes prior to an event, provided the customer was alerted as to the possibility of an event 12 hours prior to the start of the event; otherwise, customers are provided with a minimum two hours of notification. Events may last no more than six hours and may be called no more than 16 times per year.

Events may be called at the direction of the MISO, when the day-ahead MISO LMP exceeds the cost of electricity generated from No. 2 oil (given the spot price for that commodity), the forecast daily high temperature exceeds the 30-year historic annual average system peak temperature, or if MidAmerican determines that curtailment is required due to distribution or transmission system conditions.

Interruptible Load Replacement Energy Service (Rider ILR)

This rider is available only to customers participating in MidAmerican's Curtailment Service rider (see above) with a minimum interruptible load of one MW. Participation in this rider allows MidAmerican to interrupt the curtailment portion of the participant's load using automatic controls.

The incentive paid to participants is equal to the price paid by MidAmerican to purchase and deliver energy when it must do so through a reliability coordinator (i.e., the Midwest Reliability Organization or MAPP) times a factor to cover distribution and transmission (as appropriate) losses.

This rider explicitly notes that it will be in force only so long as MAPP governs MidAmerican's resource adequacy requirements.

Large General Service, Interruptible Time-of-Use at Primary Voltage for Iron Foundry (LCL)

This optional rate is available only to iron foundry customers with primary voltage, a minimum peak monthly demand of 9,000 kW, and an arc furnace with a minimum monthly peak demand of 6,000 kW and willing to allow MidAmerican to interrupt 30 per cent or more normal operating load.

The charges for this rate are the same as those for a large general service customer with primary voltage on the standard rate, except that the customer receives an additional credit of $3.13/kW per month in the summer and $2.8/kW per month in the winter, or approximately $36/kW-year.

Participants will be notified up to 30 minutes prior to curtailment if they had been notified 12 hours prior to the event beginning that an event was possible; otherwise, participants will receive two hours' notification, although the rider notes that if operating conditions require it, they may begin an event immediately upon notice.

Short-Term Interruptible Energy Service (Rider 12)

This rider is extremely vague, indicating only that MidAmerican may invite voluntary interruptions "from time to time… to avoid costly energy purchases". The incentive payment for participants would be negotiated prior to each request for interruption, as will the length of the interruption and the amount of load to be interrupted. Very little additional information is offered regarding this rider in MidAmerican's tariff book.

Contract Pricing (CJD and CTE)

CJD is a price schedule offered by MidAmerican in its North system to a single customer, Deere & Company's foundry. Demand charges and energy charges are considerably lower in winter months than the standard rate, and vary by time of day.

CTE is a price schedule offered to customers receiving electricity from Neal Station, a substation in Woodbury county. Although not explicitly stated in the rider, this substation appears to serve a fertilizer factory. This price schedule fixes the demand charge at $4.72/kW per month and energy charges at ¢2.055/kWh.

Load Retention and Load Attraction Tariffs

MidAmerican maintains a Flexible Pricing (FP) rider that applies to all of its system areas (North, South, etc.) This rider offers allows MidAmerican to offer discounted rates to encourage a customer (or group of customers) to maintain or increase load and is mandated by state legislation (administrative code 199-20.14).

The discount that may be offered is not specified, only that "Any discount offered should… significantly affect customers' decision to stay on the system… to increase consumption; or to significantly affect a prospective customer's decision."

Prior to offering a discount, MidAmerican must conduct a cost-benefit analysis that demonstrates that there is a net societal benefit of offering the discount.

The same discount must be offered to all directly competing customers in the same service territory, and may only remain in force for up to five years. No rate can be discounted to less than the marginal cost to MidAmerican of serving the given customer.

Unlike the California's load retention rate riders, no approval from an external authority is required. Under state legislation, half of the of any increase in net revenue as a result of the offered discount must be used to reduce rates for all customers while the other half may be kept by the utility.

4.2 Interstate Power and Light

Interstate Power and Light is a vertically integrated utility that is a subsidiary of Alliant Energy, that, along with Wisconsin Power and Light (another Alliant subsidiary) serves approximately one million electricity customers. Of the utilities included in the EEI study, IPL's residential to industrial ratio of average cost of electricity is the eighth highest.

This section of the Iowa chapter is divided into the following subsections:

- Industrial Rate Summary Table
- Standard Rates
- Alternative Rates and System-Driven Incentives
- Load Retention and Load Attraction Tariffs

Industrial Rate Summary Table

A high-level summary of Navigant's findings for Interstate Power and Light is shown in Table 16.

Table 16. Summary of Interstate Power and Light Industrial Rates

Interstate Power & Light (IA)						
Average Cost of Electricity (EEI "Typical Bill")						
	Residential	**Industrial**				
Peak Monthly kW:	N/A	1,000	1,000	50,000	50,000	50,000
Load Factor:	N/A	55%	89%	41%	68%	89%
Total Unit Cost ($/kWh):	$0.136	$0.074	$0.059	$0.082	$0.055	$0.051
Res/Ind Ratio	1.00	1.84	2.31	1.66	2.45	2.68
Standard Rates						
Electric Large General Service Usage (440, 447-8, 480, 487-8)						
Note: IPL is a vertically integrated utility. Rate tariffs do not show unbundled rates.						
Demand Charge:	Declining block rate, 5 thresholds of demand. $12 (>= 30 MW) to $8 (up to 200 kW), summer $5 - $8/kW winter. Demand calculated as highest On-Peak demand plus 50% of the amount that Off-Peak demand exceeds On-Peak.					
Energy Charge:	Summer price ¢2.5/1.6/kWh (On Peak/Off Peak). Winter price ¢1.6/0.7/kWh.					
Electric Large General Service — High Load Factor/Large Volume (> 25 MW and >= 10 GWh/month)						
Available only to transmission-connected customers.						
Demand Charge:	$8.45/kW					
Energy Charge:	¢0.36/kWh					
Alternative Rates & System-Driven Incentives						
Interruptible Service Option (Rider INTSERV)	Min. of 200 kW curtailable load. Bill credit of $7/kW (summer) or $4.5/kW (winter). Customer must reduce demand down to "Firm Demand" level. Used for reliability and economic dispatch. Economic dispatch occurs when marginal generation fuel in MISO is oil. Max. of 64 event hours per year.					
Day-Ahead Hourly Pricing (rider DAHP)	Participants subject to "baseline" charges at standard rate. Participants credited (or charged) based on deviation between current period energy consumption and consumption for same period 12 months previous. Credits/charges based on hour of day and voltage requirements, range from: ¢ 2.6 /kWh (2,808 hours/year, Transmission Level voltage, >34.5 kV) to ¢14 /kWh (40 hours/year, Secondary Distribution level voltage, < 4.1 kV)					
Load Retention/Attraction Tariffs						
Economic Development Rate (Rider ECON): Discounted rates may be offered under this rider if they will significantly affect the customer(s)' decision to stay on the system or add incremental load. Discounts may be offered only if cost/benefit analysis indicates that there is a net benefit to all customers and the utility. Discounts offered to a single customer must also be offered to all direct competitors in the same service territory. Discounted price may not be less than the marginal cost of serving the customer.						

Standard Rates

IPL has two open tariffs relevant to this study: the Electric Large General Service tariff and the Electric Large General Service High Load Factor/Large Volume tariff.

The standard Large GS tariff imposes demand charges in a declining block rate, with material discounts for high levels of incremental demand. The seasonal demand charges for the standard Large GS tariff are shown in Table 17.

Table 17. IPL Large GS Demand Charge ($/kW)

Demand Tier	Winter	Summer
First 200 kW	$8.21	$15.61
Next 800 kW	$7.49	$15.48
Next 9,000 kW	$6.86	$15.27
Next 20,000 kW	$6.68	$15.18
All kW over 30,000 kW	$4.98	$12.29
Source: Interstate Power and Light		

The two aspects of these prices most relevant to this study are the fact summer prices are approximately twice the winter price, and the fact that there is a significant discount for very high levels of demand — each kW beyond 30 MW is 40 per cent (winter) or 20 per cent (summer) less expensive than the first 200 kW of demand. IPL considers the summer to last from mid-June to mid-September (4 months).

For energy, large GS customers pay a default two-period TOU rate that does not vary by volume. The IPL energy rate by TOU period is shown in Table 18.

Table 18. IPL Large GS Energy Charge (¢/kWh)

TOU Period	Winter	Summer
On-Peak	1.586	2.483
Off-Peak	0.687	1.586
Source: Interstate Power and Light		

Customers outside of IPL's northern zone may choose to pay a fixed seasonal energy rate (1.073 ¢/kWh winter, 1.971 ¢/kWh summer) rather than the default TOU prices. Note that in the case of the TOU prices, the Off-Peak winter price is a quarter the On-Peak summer price. On-Peak hours run from 7am to 8pm. Recall that the winter season is in force eight months of the year.

Discounts are available to customers that provide their own transformation facilities, with customers that assume responsibility for transforming voltage from the transmission level (115 kV) eligible for a 10 per cent discount on demand charges.

IPL's second standard rate for large general service customers is the Electric Large General Service — High Load Factor/Large Volume rate. Only customers accepting transmission level voltage supply, with a minimum monthly peak demand of 25,000 kW and a minimum monthly energy consumption of 10 or more GWh qualify to receive this rate. Customers signing a service contract for this rate for a minimum of one year will pay $8.45/kW in all months and 0.364 ¢/kWh for all consumption.

Note that, as for MidAmerican, IPL's tariffs do not unbundle charges so it is impossible to determine with certainty whether differences in rates between one tariff and another are driven principally by commodity, delivery or transmission charges.

Alternative Rates and System-Driven Incentives

Navigant has identified two alternative rates offered by IPL to leverage customer flexibility to drive down system costs.

Interruptible Service Option (Rider INTSERV)

Customers with a minimum interruptible load of 200 kW qualify to participate in this rider.

Participating customers must agree, during load interruption periods, to reduce demand to some specified Contract Firm Level (CFL) demand. Participating customers earn a bill credit of $7.06/kW each month in the summer and $4.55/kW for each month in the winter, approximately $65/kW-year. The customer's total bill credit in each month is the difference between monthly peak demand and the nominated CFL load down to which participants must reduce.

IPL may dispatch interruptions for reliability, reserve margin, economic reasons or to test participant capabilities.

If an interruption is called for reserve margin or economic reasons, participants may elect to "buy-through" the event by paying a charge equivalent to the real-time LMP plus a 12 per cent mark-up.

Participants that do not reduce demand down to the CRL level will, for their first instance of non-compliance, be billed for all energy consumed above the CRL during the interruption period at the buy-through price and will additionally be fined $26.27/kW for each kW above the CRL. Any subsequent noncompliance will be fined at $52.54/kW for each kW above the CRL.

Day Ahead Hourly Pricing (Rider DAHP)

The DAHP voluntary tariff provides participating customers with the opportunity to earn bill credits by reducing their consumption, particularly in peak hours, relative to their consumption in the same hour in the previous year.

Each month, a two-step process determines each participating customer's final bill. First the customer's bill is calculated based on their demand and energy consumption and the standard rates. Next, the customer's hourly consumption in that month is compared with the same month in the previous year. All deviations between the two years (i.e., the current year and the baseline year) are multiplied by the DAHP prices for that month to either deliver to the customer a bill credit or charge. There are ten possible hourly prices that may be applied in each hour, with prices for all 24 hours announced one day ahead by noon. The set number of hours in which each price may be charged, and the ten possible prices, are shown below in Table 19.

Table 19. DAHP Hourly Energy Prices (¢/kWh)

Number of Hours Charge Applies	Transmission Level (>34.5 kV)	Primary Distribution Level (4.16 – 34.5 kV)	Secondary Distribution Level (< 4.16 kV)
2,800	2.57	3.29	3.33
1,200	3.18	3.91	3.97
1,000	3.44	4.17	4.23
500	3.89	4.65	4.71
500	4.25	5.01	5.08
900	4.91	5.69	5.77
900	5.22	6.01	6.09
820	5.63	6.42	6.52
100	8.38	9.25	9.38
40	12.66	13.64	13.84

Source: Interstate Power and Light

Note that the structure of this program is such that any customer participating will want to be reasonably certain that it is possible to reduce consumption in all hours of the year, compared to the prior year's consumption.

Load Retention and Load Attraction Tariffs

As with MidAmerican, IPL offers an economic development rate mandated by state legislation. The ECON rider for IPL is nearly identical to MidAmerican's rider since the conditions for participation, etc., are all drawn directly from legislation.

5. PENNSYLVANIA

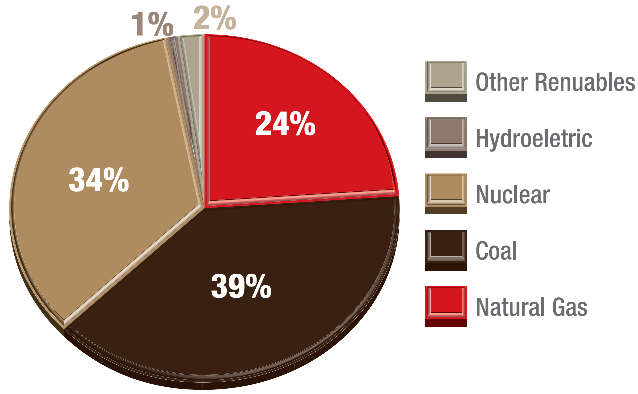
Approximately 6 per cent of Pennsylvania's installed generation capacity is made up of non-hydro renewables; however, in fact, such renewables only provide approximately 2 per cent of the state's energy. The majority of the energy is provided by fossil fuels (natural gas and coal together provide 63 per cent of energy, see Figure 6), which also make up approximately 71 per cent of installed capacity.

Navigant has completed a detailed examination of two of Pennsylvania's utilities, the Duquesne Light Company and the Pennsylvania Electric Company (PECO). Each of these utilities' industrial rates, and optional and load retention/attraction tariffs, are discussed in the first two subsections below.

Pennsylvania is an "open access" jurisdiction, in which customers may purchase their electricity from a competitive energy supplier and have it delivered (at regulated rates) by their local utility. For Navigant's survey of industrial electricity prices in Pennsylvania, we have considered only prices offered by the utility in question as the default provider of electricity (i.e., we have not surveyed prices offered by any competitive energy suppliers).

In its research, Navigant has noted that there exists in Pennsylvania and in a number of other adjoining states a significant opportunity for large customers to reduce costs by participating in PJM's capacity market. The current iteration of this market is referred to as the Reliability Pricing Model (RPM) and relies on long-term price signals to affect capacity requirements. The third subsection of the Pennsylvania chapter will discuss the opportunities for industrial customers participating in PJM's RPM.

Figure 6. Pennsylvania's Energy Generation Mix, 2012



Source: U.S. Energy Information Administration

Table 20 reproduces the part of the Table ES-1 relevant to Pennsylvania, summarizing certain key features of the entities reviewed as part of this survey.

Table 20. Summary of Pennsylvania Entities

Entity Name	Jurisdiction	Optional rates or System-Driven Incentives	Economic Development Rates	Competitive Energy Suply	Average Res : Ind. Ratio
Duquesne Light Company	Pennsylvania	✓		✓	1.9
Pennsylvania Electtric Company (PECO)	Pennsylvania	✓	✓	✓	1.6**
PJM Interconections	13 states and D.C.	✓		✓	2.0

*** Average of all utilities surveyed by EEI located in states in which PJM has a presence*

Source: Navigant analysis

5.1 Duquesne Light Company

Duquesne Light serves nearly 600,000 customers in 817 square miles of Allegheny and Beaver Counties of Pennsylvania, an area containing the city of Pittsburgh. Duquesne does not appear to offer any load retention or attraction tariffs.

This section of the Pennsylvania chapter is divided into the following subsections:

- Industrial Rate Summary Table
- Standard Rates and Voltage Incentives
- Alternative Rates and System-Driven Incentives
- Industrial Rate Summary Table

A high-level summary of Navigant's findings for Duquesne Light is shown in Table 21.

Table 21. Summary of Duquesne Light Industrial Rates

Duquesne Light Company (PA)						
Average Cost of Electricity (EEI "Typical Bill")						
	Residential	**Industrial**				
Peak Monthly kW:	N/A	1,000	1,000	50,000	50,000	50,000
Load Factor:	N/A	55%	89%	41%	68%	89%
Total Unit Cost ($/kWh):	$0.126	$0.076	$0.064	$0.060	$0.054	$0.052
Res/Ind Ratio	1.00	1.67	1.97	2.09	2.32	2.41
Standard Rates						
General Service Large (GL) (> = 300 kW)						
NB: Pennsylvania is an open-access state, meaning that customers may choose to obtain the commodity from a competitive energy supplier. Rates below are for "Default Service" (i.e., supply and transmission provided by Duquesne).						
Commodity:	Default supply as per rider No. 9, Day-Ahead Hourly Price Service. Demand charges are based on a customer's coincident peak load contribution and the requirements of the PJM Reliability Pricing Model. Energy charges are based on PJM LMP and a retail margin.					
Distribution:	$8.15/ kW					
Transmission:	$3.37/ kW					
Large Power Service (L) (> 5 MW)						
Commodity:	Default supply as per rider No. 9, Day-Ahead Hourly Price Service. Demand charges are based on a customer's coincident peak load contribution and the requirements of the PJM Reliability Pricing Model. Energy charges are based on PJM LMP and a retail margin.					
Distribution:	For voltage < 138 kV: $11/kW. For voltage > = 138 kV, no variable charge.					
Transmission:	$3.46/ kW					
Alternative Rates & System-Driven Incentives						
High-Voltage Power Service	Available to customers with On-Peak demand >= 30 MW and voltage >= 69kV. No variable distribution charge, otherwise charges identical to L rate.					

Standard Rates

The standard default service rates for Duquesne are, at a high level, relatively simple: commodity energy charges are based on combination of the day-ahead and real-time PJM LMP at the appropriate node, and demand charges are based on the customer's relative contribution to system peak and the PJM reliability pricing model.

A customer's peak load contribution is based on the average of the customer's load coincident with the peak hour of the five peak days, as determined by PJM. Note that this is very similar to the approach used in Ontario for assigning the Global Adjustment component of the commodity cost to large industrial customers.

Commodity rates are identical for both the GL (300 kW to 5 MW) and the L (5 MW or higher) tariffs.

Interestingly, distribution rates are higher ($11/kW) for L tariff customers that require a supply voltage of less than 138 kV than they are for a GL tariff customer. L tariff customers that use a supply voltage of 138 kV or above pay no distribution charge.

Alternative Rates and System-Driven Incentives

Navigant found only a single optional tariff for Duquesne, a High-Voltage Power Service tariff. This tariff provides a way for customers with very high levels of demand (>= 30 MW) that require a supply voltage of between 69 kV and 138 kV to avoid the distribution demand charge that they would otherwise be required to pay under the L tariff.

Although the possibility of a Duquesne customer participating as a demand resource under PJM's reliability pricing model is referenced in the Duquesne tariff, no rate rider or tariff is provided by Duquesne detailing this program.

5.2 Pennsylvania Electric Company

PECO is a subsidiary of Exelon Corporation and serves approximately 1.6 million customers in southeastern Pennsylvania, an area including Philadelphia.

This section of the Pennsylvania chapter is divided into the following subsections:

- Industrial Rate Summary Table
- Standard Rates
- Alternative Rates and System-Driven Incentives
- Load Retention and Load Attraction Tariffs

Industrial Rate Summary Table

A high-level summary of Navigant's findings for PECO is shown in Table 22.

Table 22. Summary of PECO Industrial Rates

Pennsylvania Electric Company (PA)						
Average Cost of Electricity (EEI "Typical Bill")						
	Residential	**Industrial**				
Peak Monthly kW:	N/A	1,000	1,000	50,000	50,000	50,000
Load Factor:	N/A	55%	89%	41%	68%	89%
Total Unit Cost ($/kWh):	$0.119	$0.065	$0.062	$0.063	$0.060	$0.059
Res/Ind Ratio	1.00	1.82	1.91	1.88	1.97	2.00
Standard Rates						
General Service (GS) (< 750 or 1,500 kVA, depending on transformer location)						
NB: Pennsylvania is an open-access state, meaning that customers may choose to obtain the commodity from a competitive energy supplier. Rates below are for "Default Service" (i.e., supply and transmission provided by PECO						
Commodity:	Customers with demand > 500 kW pay the day-ahead PJM price (energy) and the PJM reliability pricing model charge, as well as other ancillary services costs, administration, etc.					
Distribution:	Demand charge $5/kW, energy charge ¢ 0.41 /kWh.					
Transmission:	$1.71/kW					
High-Tension Power (HT) (>= 750 or 1,500 kVA, depending on transformer location)						
Untransformed service. Customers must install/own/maintain all transforming/switching, etc., equipment required.						
Commodity:	Customers with demand > 500 kW pay the day-ahead PJM price (energy) and the PJM reliability pricing model charge, as well as other ancillary services costs, administration, etc.					
Distribution:	Demand charge $3.55/kW, energy charge ¢0.15 /kWh.					
Transmission:	$1.71/kW					
Alternative Rates & System-Driven Incentives						
Interruptible Rider - Voluntary & System Reliability	Voluntary curtailment events based on economic and reliability dispatch. Payments are customer-specific as per each customer's contract. Min. of 1 hour notification. Events 2 - 8 hours in length.					
Night Service Riders	Participating customers are billed at standard rate (for distribution) for demand in On-Peak hours. Incremental kW demand in Off-Peak hours is $1 (GS) - $2/kW (HT).					
Load Retention/Attraction Tariffs						
Economic Development Rider - Employment and Load Growth: Available to existing non-manufacturing customers demonstrating sustained load increase, additional employment (10 jobs/MW), and LEED rating. Available to existing manufacturing customers that have created 10 new jobs in "Base Period" and increased load at least 100 kW. Available for customers intending to undertake brownfield development with 100 kW or more of new load. Participation yields a discount of 15% on incremental load.						
Economic Development Rider - Competitive Alternative: Available to customers that can demonstrate a viable competitive alternative to power supply from PECO, and an increase or retention of at least 1MW and 10 jobs/MW. PECO may provide a rate reduction of up to 50% to meet competitively offered rate.						

Standard Rates

Navigant has identified two PECO tariffs that are relevant to the CME, the General Service (GS) tariff, (applicable to customers with up to 1,500 kVA if the transformer is located outside of the building) and the High Tension Power (HT) tariff, applicable to the largest customers in PECO's service territory. Note that customers subject to the HT tariff are required to take delivery of supply at transmission voltage and must own and maintain any transformation equipment required.

As with Duquesne, commodity charges are relatively straightforward at a high level, with an energy component that is based on the PJM LMP for the relevant node, and a demand charge that is based on each customer's contribution to peak demand (see the description above).

Distribution charges include both a demand and an energy component. These are discounted for customers receiving supply at transmission voltage (i.e., HT tariff customers), but not nearly so much as in some of the other jurisdictions reviewed in this study.

Alternative Rates and System-Driven Incentives

Navigant has identified two rate riders offered by PECO that offer industrial customers an opportunity to reduce their electricity costs while also reducing overall system costs.

Interruptible Rider — Voluntary and System Reliability

Customers participating in this rider may choose to respond to curtailment events initiated by PECO with at least one hour's notice. The customer is not required to specify a nominated or contracted load to be curtailed or a firm demand level to which the customer will curtail. Customers are paid for curtailment based on a customer-specific contracted rate and the total energy reduction (below baseline) achieved by the customer during the event. No indication is provided in the rider as to how the baseline is calculated.

The rider does not indicate that there are any penalties or incremental costs incurred by the customer for consumption that exceeds the baseline, suggesting that this is a no-risk program for large customers.

Night Service Riders

This rider is designed to provide an incentive for GS and HT customers to transfer load to Off-Peak (8pm – 8am) hours. Under this rider customers are charged the standard distribution demand charge based on their peak demand during the On-Peak period ($5/kW for GS customers, $3.55/kW for HT customers), but if their monthly peak demand (occurring during the Off-Peak period) exceeds the On-Peak demand, the incremental kW are billed at $1.97/kW. No discount is applied to energy charges.

Note that PECO may set a cap on the number of incremental Off-Peak kW that are eligible for this discount. Should a customer exceed this cap, any incremental kW above this cap will be billed at standard rates. No specific indication is provided as to what that cap may be, only that it "… shall be dependent upon the capacity of the generation, transmission and distribution facilities available for such supply."

Load Retention and Attraction Tariffs

Navigant has identified two load attraction/retention tariffs offered by PECO: one that operates as a traditional economic development rate for attracting incremental load, the other that is designed to allow PECO to compete with energy suppliers in other jurisdictions for the business of large consumers.

Economic Development Rider — Employment and Load Growth

PECO's economic development rider possesses one particularly interesting feature not present in any of the other load retention/attraction tariffs reviewed: it is "designed to encourage environmentally sustainable growth in all sectors of the industrial and commercial group…"

There are three possible streams under which a customer may qualify to participate in this rider:

1. Existing non-manufacturing customers
2. New or existing manufacturing customers
3. New or existing customers committing to develop a brownfield site

In order to qualify for this rider, existing non-manufacturing customers must do the following:

- Demonstrate an increase of at least 500 kW in load for a minimum of three months
- Demonstrate an increase of at least ten customer employees/additional MW for the same period and,
- Achieve a Certified LEED rating

It is not clear whether discounts are credited to customers following verification of the eligibility criteria above, or whether the discount is applied prior to verification, with noncompliance resulting in a discount recovery following verification. The second of the two criteria requires a change in customer quarterly employee tax filings for verification, meaning that a customer can only be verified to have met the eligibility criteria three months after the incremental load and jobs are added.

In order to qualify for this rider, manufacturing customers (new or existing) must do the following:

- Prove that they are in fact a manufacturing operation by filing a Manufacturing Sales Tax Exemption Certificate[xxiv]
- For existing manufacturers only, provide an employment report for the 12 months immediately preceding the customer's application for the rider
- For existing manufacturers only, demonstrate the creation of a minimum of ten new jobs and the addition of at least 100 kW of demand

As with non-manufacturing customers, the conditions for eligibility may only be verified three months after the creation of incremental jobs and load, and it is unclear from the rider how discount payment is timed, given these conditions.

The only eligibility condition for a customer that develops a brownfield site is the demonstrated addition of at least 100

[xxiv] Pennsylvania exempts manufacturers from paying sales tax on the proportion of electricity service used directly for manufacturing operations. To qualify for the Certificate, a customer must certify that more than half its load is for manufacturing operations.

kW of load. PECO defines a brownfield site in the standard way as a property the development of which may be complicated by the presence or potential presence of some hazardous contaminant.

Customers subject to this rider receive a 15 per cent discount on all distribution charges related to the incremental load to which the rider applies. In the case of GS and HT customers, this results in a discount to the demand charge of 74 and 53 ¢/kW, respectively. Although it is a modest discount, there is in the rider no apparent cap on the number of participants, and the documentation requirements for participation do not appear to be unduly onerous.

Economic Development Rider — Competitive Alternative

This rider is intended to encourage the growth of new load (and employment) as well as retain existing load.

In order to qualify for this discount, a customer must do the following:

- Provide a written description of a competitive alternative to PECO's service, including documentation of the costs and viability of that alternative
- Demonstrate a sustained month-over-month increase in load by a minimum of 1 MW for three months
- Demonstrate the creation of at least ten jobs per MW or the retention of ten jobs per MW over three months

Note that, as above, the job creation/retention qualification must be demonstrated via a customer's quarterly tax filings. Although, again, as above, the timing of discount payment with respect to eligibility verification is unclear; it seems reasonable to suppose that PECO may agree to provide the discount after the first criteria is satisfied, provided that after three months the next two criteria may be verified.

PECO will negotiate the discount with the customer and may offer to discount distribution charges by up to 50 per cent in order to meet price of the customer's documented competitive alternative.

As with the load and employment growth rider above, there is no apparent cap on the number of participants in this rider, and participation is limited to five years.

5.3 Demand Response in PJM

PJM is a regional transmission organization and independent system operator that coordinates a wholesale electricity market across 13 states and the District of Columbia. PJM is responsible for running the auctions that set the prices for energy, capacity, ancillary services, and transmission rights, among others. PJM encourages energy consumers, using demand response, to participate in the forward capacity market, energy market, the day-ahead reserve scheduling market, the synchronized reserve market, and the regulation services market.

End-use consumers may participate in the demand response markets via a curtailment service provider (CSP), either a utility or an aggregator.

Economic Demand Response — Energy Market

Incentives for consumers to participate in PJM's economic demand response market are driven by Federal Energy Regulatory Commission (FERC) Order 745, a 2012 regulatory note that requires U.S. independent system operators managing electricity markets to pay DR resources participating in day-ahead and real-time markets the full locational marginal price (LMP) for electricity, when that price is such that dispatching DR is cost effective.[xxv]

In PJM's case, the cost-effective LMP is known as the Net Benefits Test (NBT) price, and, between April 2012 and January 2013, has ranged between $23 and $26/MWh.[xxvi] When the LMP (either day-ahead or real-time) exceeds the NBT, CSPs may make offers to PJM for demand response.

As of the end of May 2014, PJM had nearly 3,000 MW of registered economic demand response capability, approximately 40 per cent of which was derived from manufacturing curtailment and approximately a quarter of which was derived from behind-the-meter generation.[xxvii] Although there are more than 2,500 registered locations providing this DR, regular participation is generally limited to a small number of industrial locations with demands of 10 MW or more; in the period of January through May of 2014, there were an average of only ten unique participating registrations. In that same period, these participants delivered 60,000 MWh of economic demand response, for which they collectively received nearly $13 million. The average credit in this period was $214/MWh.

Economic Demand Response — Ancillary Services

End-use consumers may, through CSPs, also provide demand response for ancillary services, specifically synchronous reserve and regulation service. The nature of these services is such that PJM's capability requirements for these markets are much lower than for the more conventional energy market.

Synchronous reserve service ("spinning" reserve) is a stand-by service intended to supply electricity when there is an unexpected system need at very short notice. From January through May of 2014 there were an average of 363 MW of DR participating in the synchronous reserve market. Although this market is cleared every hour, DR resources are called

[xxv] *The Electric Power Supply Association, an organization of power generators, recently (in May 2014) won a Court of Appeals case to overturn this regulation, arguing that the Order encroaches on the states' exclusive jurisdiction to regulate the retail market. So far, PJM has not yet changed any of its rules or payment schemes for the dispatch of economic DR.*

[xxvi] *PJM Interconnection, 2012 Economic Demand Response Performance Report, March 2013.*

[xxvii] . *PJM Interconnection,* 2014 Demand Response Operations Markets Activity Report: June 2014, *June 2014.*

relatively infrequently to supply reserves. Given the total energy supplied by DR resources for synchronous reserve in the period mentioned above, and the average capability, there were on average approximately 160 hours of actual DR required of participants in each month — about 20 per cent of the hours in an average month. The average payment in this period for DR synchronous reserves was $13.50/MWh.

Regulation service corrects for short-term fluctuations in electricity that may affect the stability of the power system by helping to match generation with load and by adjusting generation output to maintain the desired frequency. From January through May of 2014, there were an average of 8 MW of DR participating in the regulation market. In this period the average payment for DR regulation service was just over $70/MWh, although in January payments were as high as $149/MWh.

Forward Capacity Market — The Reliability Pricing Model (RPM)

PJM administers a forward capacity market in which "load-serving entities" (LSEs) may bid to provide capacity for a delivery period three years in the future. DR resources (CSPs) are also encouraged to bid into this market. DR resources bidding into the RPM may bid for one of three capacity products, with one of three minimum notification ("lead") times.

The three DR capacity products are:

- Limited DR: The resource must be available for up to ten weekdays from June through September, with a maximum event length of six hours.
- Extended Summer DR: The resource must be available for all days from May through October, with a maximum event length of ten hours.
- Annual DR: The resource must be available on every day for 12 months beginning in June, with a maximum event length of ten hours.

The three possible minimum notification times are 30, 60 or 120 minutes.

6. TEXAS

The vast majority of both the installed capacity and annual energy generated are provided by fossil fuel-fired generation, somewhat supplemented by nuclear power and non-hydro renewables (see Figure 7, below).

Navigant has completed a detailed examination of Entergy Texas Inc., a vertically integrated utility in the southeast region of Texas. The majority of the Texas electricity market and system is administered by the Electric Reliability Council of Texas (ERCOT). ERCOT is the ISO serving the deregulated territory in Texas.

Some utilities operating near the Texas borders, including Entergy Texas, are not included in

The distribution of total capacity for delivery from June 2014 through May 2015 by notification time and product type is shown in Table 23.

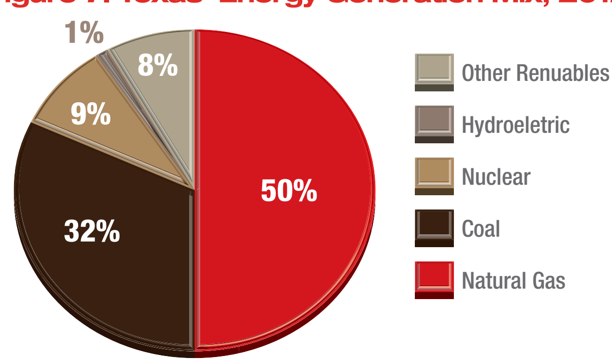
Table 23. Distribution of DR Capacity by Product and Notification Requirement

DR Product	Capacity (MW)	Proportion of whole
Limited DR	8,213	88%
Extended DR	1,104	12%
Annual DR	43	0.5%
Total	9,360	100%
Source: PJM Interconnection		

Minimun Notification	Capacity (MW)	Proportion of whole
120 minutes	8,170	87%
60 minutes	486	5%
30 minutes	704	8%
Total	9,360	100%
Source: PJM Interconnection		

The total capacity credits paid for the period from January through May of 2014 were on average more than $46 million per month. Assuming this average is also representative of the period from June through December 2013, and given that the total DR capacity for delivery year 2013/2014 was nearly 9,000 MW[xxviii]; this suggests that the average value of all three DR products and notification types was approximately $62 per kW-year. Note that it is likely that the clearing price for each product increases with the flexibility required of it, so the auction-clearing price for Annual DR with only 30 minutes notification is likely to be considerably higher than the average price noted above.

Figure 7. Texas' Energy Generation Mix, 2012



Source: U.S. Energy Information Administration

[xxviii] *PJM Interconnection, 2013 Demand Response Operations Markets Activity Report: October, October 2013.*

ERCOT. Entergy Texas is a vertically integrated utility that supplies power to Texans that is, in fact, generated out-of-state.

Table 24, below, reproduces the part of the Table ES-1 relevant to Texas, summarizing certain key features of the entity reviewed as part of this survey.

Table 24. Summary of Texas Entity

Entity Name	Jurisdiction	Optional rates or System-Driven Incentives	Economic Development Rates	Competitive Energy Suply	Average Res : Ind. Ratio
Entergy Texas	Texas	✓			2.0
Source: Navigant analysis					

This chapter of the report, focusing on Entergy Texas, is divided into the following subsections:

- Industrial Rate Summary Table
- Standard Rates
- Alternative Rates and System-Driven Incentives

Industrial Rate Summary

A high-level summary of Navigant's findings for Entergy Texas is shown in Table 25.

Table 25. Summary of Entergy Texas Industrial Rates

Entergy Texas (TX)						
Average Cost of Electricity (EEI "Typical Bill")						
	Residential	Industrial				
Peak Monthly kW:	N/A	1,000	1,000	50,000	50,000	50,000
Load Factor:	N/A	55%	89%	41%	68%	89%
Total Unit Cost ($/kWh):	$0.110	$0.067	$0.056	$0.062	$0.052	$0.048
Res/Ind Ratio	1.00	1.64	1.95	1.78	2.12	2.27
Standard Rates						
Large General Service (LGS) (300kW - 2,500kW)						
NB: Entergy Texas is a vertically integrated energy company. Rate tariffs do not show unbundled rates. Demand charges are based on "Contract Power", the peak demand observed over the previous 12 months for the given customer.						
Demand Charge	$10.74 - 12.06/kW, varies by voltage level.					
Energy Charge	0.46 ¢kWh, plus "fixed fuel factor" (FFF) from 3.9¢/kWh-4.2¢/kWh (varies by voltage). FFF changes semi-annually to reflect wholesale cost of electricity.					
Large Industrial Power Service (>2,500 kW)						
Demand Charge	Ranging from $7.39/kW - $6.84/kW depending on season and delivery voltage.					
Energy Charge	0.47¢kWh up to 584kWh for each kW of billing load, and 0.3123¢/kWh for additional kWh. In addition to this, same FFF as for LGS tariff customers.					
Alternative Rates & System-Driven Incentives						
Large GS with time-of-day (TOD)	Optional. Demand charge $15/kW in summer, $7.75/ kW in winter. Base energy price ranges from 0.38 ¢/kWh for Off-peak consumption (all seasons) to 0.45 ¢/kWh (winter, On-peak) or 1.25 ¢/kWh (summer, On-peak). NB: no change to FFF.					
Large Industrial Power Service with TOD	Optional. Demand charge $8/kW in summer, $6/kW in winter. No change to energy charges.					
Rider to Schedule Large Industrial Power Service (LIPS) for Planned Maintenance	Customers may receive bill credits by scheduling maintenance requiring load reductions in the months of June through September.					
Experimental Rider to Schedules LIPS and LIPS-TOD for Interruptible Service	Customers with Contract Power of >2.5 MW willing to nominate at least 2 MW of interruptible load may receive payments of between $45 and $60/kW-year, depending on notice required for interruption. This is a MISO program.					
Competitive Generation Service (CGS)	Customers with Contract Power of >2.5 MW may contract with a competitive energy supplier for up to 115 MW of capacity.					

Standard Rates and Voltage Discounts

There are two standard tariffs offered by Entergy Texas that are relevant to this survey: the Large General Service (300 — 2,500 kW) (LGS) tariff and the LIPS (> 2,500 kW) tariff. Entergy does not provide unbundled rates in its tariff sheets — rates are split only between demand and energy.

Entergy Texas' demand charges are summarized in Table 26, below.

Table 26. Demand Charges ($/kW per month) Entergy Texas Large Industrial Customers

Tariff Sheet		LGS	LIPS	
Season		N/A	May–October	November–April
Secondary Voltage		$12.06	$8.68	$8.13
Primary Voltage		$11.37	$8.68	$8.13
Transmission Voltage	(69kV)	$10.74	$7.44	$6.89
	(138kV)	$10.74	$7.12	$6.57
	(230kV)	N/A	$6.71	$6.16
Source: Entergy Texas				

LGS tariff customers pay a flat base rate for energy –¢0.459/kWh. LIPS tariff customers pay a base rate of ¢0.47/kWh for the first 584 kWh consumed for every kW of demand and 0.31¢/kWh for all energy consumed after that, in effect offering a (admittedly weak) incentive to customers to increase their load factor. In addition to this base charge, all customers pay the "fixed fuel factor" (FFF), a fuel surcharge that is updated semi-annually to reflect the changing supply costs to Entergy. The FFF charged to customers varies by delivery voltage, to reflect the different loss factors.

Table 27. Fixed Fuel Factor

Delivery Voltage	Fixed Fuel Factor
Secondary	¢4.22741 per kWh
Primary	¢4.11922 per kW
69kV/138kV	¢3.95962 per kWh
230kV	¢3.95962 per kWh
Source: Entergy Texas	

Note that Entergy Texas demand charges are based on "Contract Power", the peak demand of a given customer observed in the previous 12 months.

Alternative Rates and System-Driven Discounts

Navigant has identified four alternative rates offered by Entergy Texas to leverage customer flexibility to place downward pressure on system costs.

Large General Service with Time of Day (LGS-TOD)

LGS tariff customers electing to subscribe to this optional rate receive a discounted winter demand charge ($7.76) in exchange for a higher summer demand charge ($14.95). Summer is defined as the period from May through October.

The base energy charge during the Off-peak period is 0.38¢/kWh all year, the winter On-peak energy charge is 0.448¢/kWh, and the summer On-peak energy charge is 1.249¢/kWh. The summer On-peak period extends from 1pm to 9pm on non-holiday weekdays. The winter On-peak period runs from 6am to 10 am and 6pm to 10pm on non-holiday weekdays. Note that LGS-TOD customers pay the same FFF as standard LGS tariff customers.

Large Industrial Power Service Time of Day (LIPS-TOD)

LIPS customers electing to subscribe to this optional rate receive a discounted winter demand charge ($5.92/kW) in exchange for a higher summer demand charge ($8.14/kW). Summer is defined as above. Note that the price differential between seasons is much narrower for LIPS tariff customers than it is for LGS tariff customers.

LIPS-TOD tariff customers pay the same energy charge as LIPS tariff customers. Despite this tariff's name, it is not in fact a time-of-day rate, but rather a seasonal rate.

Rider to Schedule LIPS for Planned Maintenance

Customers that provide Entergy with at least one month's notice may receive bill credits for load reductions due to plant or process shutdown for planned maintenance, provided this occurs in the months from June through September. Customers participating in this rider receive a bill credit equivalent to the difference between actual peak demand in the maintenance period and Contract Power or the difference between actual peak demand in the maintenance period and the previous month's peak demand, whichever is lower.

Experimental Rider to Schedules LIPS and LIPS-TOD for Interruptible Service

Customers with Contract Power of 2.5 MW or more, willing to nominate at least 2 MW of interruptible load and accepted by Midcontinent Independent System Operator (MISO)[xxix] as a Load Modifying Resource (LMR) may participate in this program. Participants may elect to be interruptible with no notice or with five minutes' notice. Customers choosing the "no-notice" option are paid $58.56/kW-year and customers choosing the five minutes' notice option are paid $45/kW-year. The "no-notice" option is effectively an auto DR program, with curtailment being controlled directly by Entergy Texas.

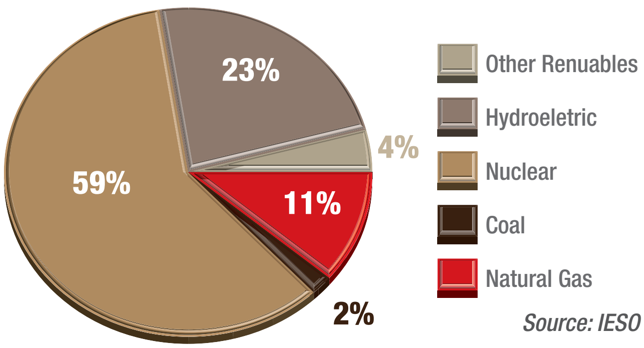
Participants with five minutes' notice will be curtailed no more than 600 hours in a given year, with limits on the number of interruptions (and length of interruptions) that may occur in any given month, week or day. There is no limit to the number of frequency of "no-notice"/auto DR interruptions.

7. ONTARIO

The vast majority of the energy generated in Ontario is produced by nuclear or hydroelectric generating stations (approximately 82 per cent of total, see Figure 8, below). While natural gas provides only approximately 11 per cent of energy, natural gas-fired plants contribute nearly a third of Ontario's installed capacity, serving principally to serve Ontario's summer peak demands.

Table 28 reproduces the part of the Table ES-1 relevant to Ontario, summarizing certain key features of this jurisdiction.

Figure 8. Ontario's Energy Generation Mix, 2013



Source: IESO

Table 28. Summary of Ontario

Entity Name	Jurisdiction	Optional rates or System-Driven Incentives	Economic Development Rates	Competitive Energy Suply	Average Res : Ind. Ratio
N/A	Ontario	✓	✓		2.0
Source: Navigant analysis					

This chapter of the report is divided into the following subsections:

- Industrial Rate Summary Table
- Standard Rates
- Alternative Rates and System-Driven Incentives
- Load Retention and Load Attraction Tariffs

Industrial Rate Summary Table

A high-level summary of Navigant's findings for Ontario are shown in Table 29.

The "LTEP" referenced below is the Ontario Ministry of Energy's Long-Term Energy Plan.[xxx]

[xxix] *Formerly the Midwest Independent System Operator.*
[xxx] *Ontario Ministry of Energy, Achieving Balance: Ontario's Long-Term Energy Plan, December 2013, http://www.energy.gov.on.ca/docs/LTEP_2013_English_WEB.pdf.*

Table 29. Summary of Ontario Industrial Rates

Ontario		
Average Cost of Electricity (EEI "Typical Bill")		
	Residential	**Large Industrial**
Peak Monthly kW:	N/A	5,000
Load Factor:	N/A	75%
Total Unit Cost ($/kWh):	$0.156	$0.079
Res/Ind Ratio	1.00	1.98
Standard Rates		
Classe B — General Services (50kW–5,000kW)		
Commodity:	The wholesale spot cost of electricity — the Hourly Ontario Electricity Price (HOEP) as set by the IESO, plus the Global Adjustment. The average GA charge from Jan through May 2014 was 3 ¢/kWh	
Distribution:	Varies by distribution company, Hydro One rate: $11.49/kW and 0.56 ¢/kWh.	
Transmission:	$2.95/kW, a credit of $0.6/kW and 0.14¢/kWh for customers that provide transformation.	
Classe A Large Users (>=5,000 kW)		
Commodity:	The wholesale spot cost of electricity — the Hourly Ontario Electricity Price (HOEP) as set by the IESO, plus the Global Adjustment. Global Adjustment amount based on contribution to system peak during peak hour of top 5 days a year.	
Distribution:	No charge for transmission-connected customers. Distribution-connected customers (sub-transmissiom) pay between $1.6–$3.6/kW depending on voltage and as much as $650/km of necessary to connectthe customer (per month).	
Transmission:	Demand charge of $3.23/kW, based on kW coincident with system peak or 85% of non-coincident peak from 7 am to 7 pm (whichever is larger), plus $ 2.27/kW for monthly peak kW.	
Alternative Rates & System-Driven Incentives		
DR3:	Monthly payment of $65/MW per contracted hour of availability (either 100 or 200 depending on contract). Per event payment of $200–$300/MWh curtailed (varies by length of event). In 2012 five events were called, each one 4 to 5 hours in length.	
Industrial Accelerator Program (IA)	A conservation program — in exchange for a contractual commitment from the customer to deliver specific levels of energy savings, participants may receive attractive financial incentives to fas-track innovative process changes and equipment retrofits.	
Load Retention/Attraction Tariffs		
Northern Industrial Electricity Rate Program (NIER): Geographically tergeted load retention; the NIER provides a 2 ¢/kWh (~25%) discount to large industrial customers in Northen Ontario. Funding for this program is set at $120 million/year until the end of 2016.		
Induatrial Electrict Incetive Program (IEI): A two stream load retention/load attraction program. New customers developping facilities and creating employment in technologies, products or processes currently used in Ontario are elegible for a fixed "all-in" electricity price for 20 years. Existing customers wishing to expand their facilities may be elegible for a cap applied to current rates for up to five years.		

Standard Rates

Note that there are over 70 regulated electricity distributors in Ontario — "local distribution companies" (LDCs), each with different distribution charges. Given this, where examples of distribution charges are required, Navigant has provided those used by Hydro One Networks, the provincial transmitter, but also the single largest distributor (and the one with by far the most large electricity consumers).

There are two relevant rate classes in Ontario: Class A customers (> 5 MW) and Class B customers (50–5,000 kW). There are approximately 57,000 Class B customers in Ontario and 550 Class A customers.[xxxi]

Both Class A and Class B customers' commodity charge is the sum of two parts, the Hourly Ontario Electricity Price (HOEP, the wholesale price of electricity in the IESO-settled market) and the Global Adjustment (GA). The Global Adjustment is calculated as the difference between the HOEP and the following:

- The regulated rates for most of Ontario's nuclear fleet and baseload hydroelectric generating stations
- Generator contracts, particularly for natural gas peaking generation and non-hydro renewables (i.e., wind and solar)
- Other existing contracted rates administered by the Ontario Electricity Financial Corporation

[xxxi] *Ontario Energy Board, 2012 Yearbook of Electricity Distributors, August 2013, http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Reporting+and+Record+Keeping+Requirements/Yearbook+of+Distributors.*

The two components of the commodity charge are, in a certain sense, off-setting; a low HOEP results in a high GA, and vice versa.

Although both Class A and Class B customers pay the same HOEP charge, the manner in which the two groups of customers is charged for the GA is very different. In the case of Class B customers, the GA is recovered through an energy charge set by the regulatory agency (the Ontario Energy Board, OEB) that varies monthly. Class A customers, on the other hand, pay only based on their contribution to system peak in the peak hour of the top five system demand days of the year. This has resulted in a considerable demand response on the part of very large industrial customers with flexible loads.

Class B customers pay both a demand and an energy charge distribution. Class A customers that are connected to the distribution network ("sub-transmission" customers) pay between $1.6 and $3.6 kW, depending on the voltage at which they receive supply. Subtransmission customers are also required to pay up to $650 per kilometre per month to cover the facilities required to serve them.[xxxii] Large industrial customers that are directly connected to the transmission system pay no distribution charges.

Both Class A and Class B customers may receive a modest energy and demand charge discount for providing their own transformation facilities.

Transmission-connected Class A customers pay a demand transmission rate that is calculated based on the larger of: that customer's contribution to system peak demand in the given month, or 85 per cent of that customer's (non-coincident) peak demand observed between 7am and 7pm.

Alternative Rates and System-Driven Incentives

There are no optional rates for industrial customers in Ontario, although there are two programs offered by the Ontario Power Authority (OPA) that offer industrial customers financial incentives for reducing overall system costs.[xxxiii]

The OPA's DR3 program is a standard large customer demand response program in many ways: customers may be called upon to curtail some contracted amount of demand when called upon by the system operator; participants may be called up to 100 or 200 hours per year (depending on whether they elect to participate in Option A or Option B) within a specific window of time each day (depending on the season).

The most interesting aspect of the DR3 program is the manner in which it provides an incentive to customers to participate despite historically calling relatively few events (only five events, none longer than five hours, were called in 2012).[xxxiv] In addition to paying between $200 and $300 for each MWh curtailed, the OPA pays participants a standard rate of $65/MW per hour for each hour of the year in which they must be available for curtailment – approximately 1,600 hours per year. This suggests that even if no events are called (and therefore no "utilization" payments made), that the OPA values DR3 capacity at over $100/kW-year.

The OPA also administers the Industrial Accelerator Program (IA). Although the IA is classified as a conservation program, it shares many similarities with certain aspects of PJM's energy efficiency demand response. The key aspect of this program that makes it relevant for this study is the requirement that participants make a contractual commitment to reduce energy consumption by some nominated amount. In exchange for this commitment, participants receive financial assistance to bring forward investment in major energy efficiency projects, with OPA funding levels set such that these projects offer a rate of return that is competitive with other possible capital investments.

The IA offers funding to participants in three different streams, processes and systems, retrofits, and "high-performance" new construction.

Load Retention and Load Attraction Tariffs

Ontario currently offers two programs that serve the purpose of economic development tariffs: the Northern Industrial Electricity Rate Program (NIER) and the Industrial Electricity Incentive Program (IEI).

The NIER is a geographically targeted load retention program, designed explicitly to: "… support continued growth and development in the northern resource and manufacturing sector."[xxxv] As indicated in the name, this program is designed specifically to preserve existing employment in northern Ontario. The Employment Insurance (EI) economic region of Northern Ontario has, in the first half of 2014, an average unemployment rate one and a half to twice as highxxxvi as the unemployment rate in all other EI economic regions of Ontario.[xxxvii]

The NIER offers very large forestry, mining and steel production companies located in Northern Ontario a rebate of 2 ¢/kWh on up to 1 TWh or 115 per cent of forecast annual consumption, whichever is lesser — i.e., the rebate is capped at $20 million per participant per year. In order to participate, a customer from an eligible industrial sector located in Northern Ontario must file a comprehensive Energy Management Plan (EMP) with the ministry. The structure for the EMP is spelled out in detail in the program rules, and must include (among other things): descriptions of current processes and key

[xxxii] *As noted above, these example rates are for Hydro One customers.*
[xxxiii] *There is, implicitly, a third program not mentioned here – the standard Class A rate. This is sometimes referred to (i.e., in the LTEP) as the "Industrial Conservation Initiative".*
[xxxiv] *Ontario Power Authority prepared by Freeman, Sullivan & Co., 2012 Impact Evaluation of Ontario Power Authority's Commercial and Industrial Demand Response Programs, August 2013, http://powerauthority.on.ca/sites/default/files/conservation/2012-DR-CI-Evaluation.pdf.*
[xxxv] *Ontario Ministry of Energy, Achieving Balance: Ontario's Long-Term Energy Plan, December 2013, http://www.energy.gov.on.ca/docs/LTEP_2013_English_WEB.pdf.*
[xxxvi] *Human Resources and Skills Development Canada, Unemployment Rates for the EI Economic Regions, accessed July 2014, http://srv129.services.gc.ca/rbin/eng/rates.aspx?id=2014#data.*
[xxxvii] *For reference, there are three EI economic regions in Nova Scotia: Halifax, Eastern and Western Nova Scotia. These regions each had an unemployment rate in July 2014 of 5.4%, 11.3%, and 15.1%, respectively.*

challenges to achieving energy reduction goals, supporting documentation for current electricity consumption quantities and costs, and the identification of energy efficiency improvements undertaken since 2006, as well as those that are forecast to be implemented or currently under way.

Funding for this program was $150 million per year for 2010 through 2013 and is now $120 million per year through to the end of 2016. The program is currently fully subscribed.

The IEI is a load attraction tariff for new and existing customers and offers participants a reduced electricity rate in exchange for "… bringing new investment and employment opportunities to the province." Customers may participate in one of three "Streams".

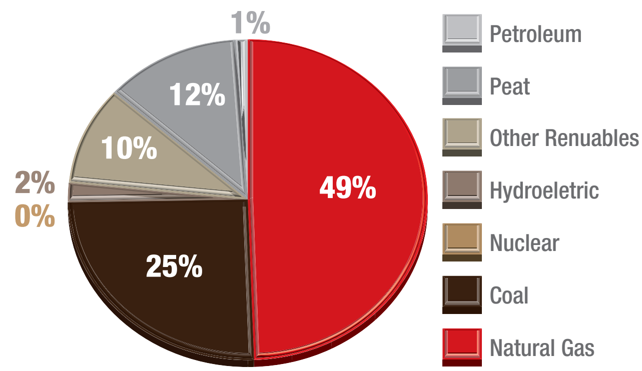
New and existing customers may participate in IEI's Stream 1, which offers participants a 20-year fixed, "all-in" electricity rate in exchange for the customer undertaking a large capital investment in technologies, products or processes not currently being used or produced in Ontario. Stream 2 offers existing customers that are planning a significant expansion of an existing facility or the construction of a new facility a cap on current electricity rates that may last up to five years. Stream 3 (currently under development) will offer as yet unspecified discounts to new and existing customers in certain specific energy-intensive industries that are building new facilities or upgrading and expanding existing facilities.

8. IRELAND

Although Ireland[xxxviii] has greatly expanded its portfolio of renewable generation in recent years — as of 2012, wind generation represented nearly a quarter of installed capacity[xxxix] — the island's energy consumption mix is still dominated by fossil fuels, with three-quarters of consumed energy being generated through the combustion of either coal or natural gas (see below). Interestingly, Ireland supplies a nontrivial amount of energy consumption via peat-burning generation.[xl]

Table 30 reproduces the part of the Table ES-1 relevant to Ireland, summarizing certain key features of this jurisdiction.

Figure 9. Ireland's Energy Generation Mix, 2012



Source: SEAI

Table 30. Summary of Ireland

Entity Name	Jurisdiction	Optional rates or System-Driven Incentives	Economic Development Rates	Competitive Energy Suply	Average Res : Ind. Ratio
N/A	Ireland	✓	✓	✓	2.0
Source: Navigant analysis					

This chapter is divided into the following sections:

- Industrial Costs Summary Table
- Costs and Cost Drivers
- System-Driven Incentives

Industrial Costs Summary Table

A high-level summary of Navigant's findings for Ireland is shown in Table 31.

[xxxviii] *Note that in this study references to "Ireland" should be understood to refer to the entirety of the island – both the Republic of and Northern Ireland – unless otherwise explicitly noted.*
[xxxix] *International Renewable Energy Agency, Ireland – Market Overview, accessed July 2014, https://www.irena.org/DocumentDownloads/Publications/GWEC_Ireland.pdf.*
[xl] *Sustainable Energy Authority of Ireland, Energy in Ireland 1990 – 2012, December 2013, http://www.seai.ie/Publications/Statistics_Publications/Energy_in_Ireland/Energy_in_Ireland_1990_-_2012_Report.pdf.*

Table 31. Summary of Ireland Industrial Rates

Ireland					
Average Cost of Electricity (Eurostat Survey of Invoices)					
	Residential	**Industrial**			
Annual Energy (MWh):	2.3–15	500–2,000	2,000–20,000	20,000–70,000	70,000–150,000
Total unit cost (€/kWh):	0.23	0.14	0.12	0.10	0.09
Res/Ind Ratio	1.00	1.64	1.94	2.19	2.43
Average Electricity Cost (Eurostat)					
Commodity (Generation):	0.5–2 GWh/Year 2–20 GWh/Year 20–70 GWh/Year 70–150 GWh/Year	€ 0.091 /kWh € 0.088 /kWh € 0.076 /kWh € 0.076 /kWh			
	Competitive energy supply market. Rates appear to be flexible and negotiated on a customer-specific basis.				
Network Fees (Dx and Tx):	0.5–2 GWh/Year 2–20 GWh/Year 20–70 GWh/Year 70–150 GWh/Year	€ 0.043 /kWh € 0.026 /kWh € 0.014 /kWh € 0.014 /kWh			
Taxes and Leveies:	0.5–2 GWh/Year 2–20 GWh/Year 20–70 GWh/Year 70–150 GWh/Year	€ 0.004 /kWh € 0.003 /kWh € 0.003 /kWh € 0.003 /kWh			
	VAT is 13.5% but is recoverable by businesses. PSO (see below) has previously been offset almost 100% by a Large Energy User rebate that expired in Sept of 2012. Excise taxes are 50% those paid by residential customers.				
Demand Response					
Demand Side Units (DSU):	Dispatched loads of 4 MW and up may paticipate in the SEM (see below) as generators — receive availability payments of as much as € 62/kW year				
Winter Peak Deman Reduction Scheme (WPDRS):	Defunct energy DR program. Customer paid an incentive of €224/MWh to reduce consumption between 5 pm and 7 pm during the period Nov. 5 through Feb 22.				
Powersave:	Standard DR program with most lucrative payments for curtailment between 5pm and 7pm in the months of Nov through Feb.				
Short-Term Active Demand Response (STAR):	Auto DR program. Two second notice, events last 5–10 minutes. Customers may nominate discrete loads to participate. Availability payment of €8.20/MWh that is available for curtailment between 7 am and midnight, all days of the year.				

Detailed Discussion of Costs and Cost Drivers

Commodity (Generation) Costs

Ireland's electricity was deregulated in the 2009, allowing business customers greater choice in their electricity supplier. Over the first year and a half of deregulation, approximately a fifth of "large energy users" (LEUs) switched energy suppliers. The principal driving factors behind these switches were lower costs offered by the new supplier (90 per cent) and the provision of flexible tariffs to better accommodate individual customer needs (40 per cent).[xli]

Navigant has not been able to uncover specific rates charged by energy suppliers to LEUs for the generation and supply component of the energy they consume – it appears as though rates may be negotiated on a customer-by-customer basis. Navigating to the website of Electric Ireland, LEUs may "request a quote" for electricity rates, but none are provided online.

In general, though, according to Eurostat figures, it appears as though larger industrial customers pay between 20 per cent and 35 per cent less per kWh for the commodity portion of the electricity they consume than do residential customers. This differential is almost certainly driven by the volatility of Irish wholesale electricity prices. Given that half of Ireland's energy generated is produced from natural gas, and the volatility of European natural gas prices over the past five years, it is possible that this gap is driven by premiums charged to residential customers for price certainty. Evidence for this is suggested by trends in domestic and large industrial electricity prices charted by the Sustainable Energy Authority of Ireland in their semi-annual price report[xlii]; industrial prices show both increases and decreases over the period of analysis (reflecting, among other things, the varying cost of

[xli] *Commission for Energy Regulation, Electricity Prices and Competition, presented to the SEAI conference, July 2010, http://www.seai.ie/Your_Business/Large_Energy_Users/LIEN/LIEN_Events/CER_Presentation_on_Electricity_Prices_and_Competition.pdf.*

[xlii] *Sustainable Energy Authority of Ireland, Electricity and Gas Prices in Ireland, June 2014, http://www.seai.ie/Your_Business/Large_Energy_Users/LIEN/LIEN_Events/CER_Presentation_on_Electricity_Prices_and_Competition.pdf.*

gas in Europe), whereas residential electricity prices show only a steady upward climb over time.

In addition to fluctuating natural gas prices, additional wind capacity installed due to policy-driven incentives has, due to its position in the dispatch merit order, served to reduce the wholesale price of electricity, a cost saving more likely passed through to customers with the most dynamic rates (i.e., LEUs). Additional wind has reduced the wholesale price,[xliii] resulting in more getting picked up by the Public Service Obligation levy (PSO).

Network Fees (Dx and Tx)

According to Eurostat figures, industrial customers pay between 45 per cent and 80 per cent less for T&D fees than do residential customers, with the discount increasing as does the volume of customer energy consumption. This suggests that there are considerable discounts for transmission-connected customers and for customers that can accept higher voltage supply. Two other interesting features of the manner in which T&D costs are recovered in Ireland are that transmission costs are recovered not just from loads, but also from generators, and that the level of those charges varies by location — the farther away from customers a generator is located, the higher are its transmission fees.[xliv]

Taxes and Levies

It is in the realm of taxes and levies that there exists the greatest difference between residential and industrial electricity costs; taxes and levies paid by industrial customers are between 90 per cent to 95 per cent lower than those paid (per kWh) by residential customers. This is driven by three components: a difference in effective Value-Added Tax (VAT) rate, excise tax rate, and the Public Service Obligation levy (PSO).

The difference in excise taxes is the most straightforward – industrial customers pay half of what residential customers must pay. For value-added tax (VAT), although all customers are nominally required to pay 13.5 per cent, large business customers have the ability to recover nearly all of that amount after the fact.[xlv]

The final levy of interest is the PSO. The PSO is in some ways analogous to Ontario's Global Adjustment (GA) – it covers the additional costs of wind and peat generation not covered by the wholesale market price and is used to cover the difference between natural gas generator contracted rates and the wholesale energy price when the wholesale energy price falls below the contracted price. Residential and small commercial customers pay a monthly fixed fee (i.e., not tied to consumption or demand) for the PSO, but industrial customers pay a volumetric fee: approximately one Euro per kVa in 2012 and 2013.[xlvi] However, in fact, LEUs paid, between 2009 and the end of September 2012, only a small fraction of the PSO levy. In this period, the Commission for Energy Regulation (CER) established a program of LEU Customer Credits "as a result of a Government decision to support large industry, given concerns about the impact of energy prices on competitiveness and the LEUs substantial contribution to employment."[xlvii] This credit not only almost completely offset the PSO charge – the credit was only 3 Euro cents less per kVa than the PSO levy noted above – but it also credited LEUs with a rebate of 1.5 Euro cents per kWh of consumption.

Although the LEU rebate was (so far as Navigant has been able to detect) discontinued in 2012, the current enormous relative differential between residential and industrial taxes and levies per unit suggests that it has been replaced (either explicitly or implicitly) by some other policy mechanism to support Irish employment policy goals.

System-Driven Incentives

As part of its survey of this jurisdiction, Navigant has found four programs relevant to this study. All programs are administered by EirGrid, the independent Transmission System Operator and Market Operator for the Republic of Ireland. EirGrid is also the owner of the System Operator of Northern Ireland and operates the Single Electricity Market (SEM) on the island of Ireland.

The four programs (referred to as "schemes" by the program administrator) relevant to this survey that are offered to industrial electricity customers are: Demand Side Units (DSUs), the Winter Peak Demand Reduction Scheme (WPDRS), Powersave, and Short-Term Active Response (STAR).

DSUs are either individual customers or customers participating via an aggregator that participate in the SEM as dispatchable loads. To register as a DSU, a customer must have a minimum of 4 MW of DR capacity. Customers with more than 10 MW of DR capacity must register as standalone DSUs, whereas customers with between 4 and 10 MW may choose to participate via an aggregator. Demand side units participate in the SEM as generators and bid in prices, quantities, and availability. The principal source for DSU payments is availability payments. These may be as much as €62/kW-year for 24-hour availability.[xlviii]

[xliii] European Commission, Energy prices and costs report SWD(2014) 20 final/2, March 2014, http://ec.europa.eu/energy/doc/2030/20140122_swd_prices.pdf (p. 236).

[xliv] Petrov, Dr. Konstantin and Keller, Dr. Katja, Network Pricing Models in Europe — From Normative Principles to Practical Issues, 2009, http://www.dnvkema.com/Images/Network%20Pricing%20Models%20in%20Europe.pdf.

[xlv] Sustainable Energy Authority of Ireland, Electricity and Gas Prices in Ireland, June 2014, http://www.seai.ie/Your_Business/Large_Energy_Users/LIEN/LIEN_Events/CER_Presentation_on_Electricity_Prices_and_Competition.pdf.

[xlvi] Commission for Energy Regulation, Public Service Obligation Levy 2012/2013, August 2012, http://www.dcenr.gov.ie/NR/rdonlyres/E4E9814A-A79A-4FA7-8CBA-DDA822D26024/0/cer121211August.pdf.

[xlvii] Sustainable Energy Authority of Ireland, Electricity and Gas Prices in Ireland, November 2010, http://www.seai.ie/Publications/Statistics_Publications/Electricity_and_Gas_Prices/Electricity_and_Gas_Prices_in_Ireland_january_to_june.pdf.

[xlviii] Single Electricity Market Operator, Demand Side Units in the SEM, September 2013.

WPDRS is a scheduled DR program that ran from 2003 through to the beginning of 2013. Participating customers would nominate a Committed Level (CL) of demand that would reduce demand to between the hours of 5pm and 7pm from November 5th to February 22nd of each year. For each MWh of successful curtailment (i.e., when actual demand is less than the CL) participants would be paid €224. For each MWh during the time period that was higher than the nominated CL, participants would be charged €783. A participant with a perfect curtailment record in a given winter season could expect to earn approximately €50 per kW curtailed between 5pm and 7pm.[xlix]

Powersave is available to large customers that have the demonstrated ability to reduce load by at least 100 kW when called to do so by EirGrid and have a Revenue Standard Quarter Hourly meter installed. Powersave events may be called at any time of day on any non-holiday weekday of the year. Participants are paid 95 Euro cents per kWh curtailed during the peak period (5pm to 7pm, November through February) and 38 Euro cents per kWh curtailed during the off-peak period (all other times).[l] Although the program rules indicate that there will be at least one event per year, they do not give any indication as to the expected event frequency.

STAR is an automated demand response program designed for short-term requirements. Customers participating in this scheme must consent to having their loads controlled via under-frequency relay (estimated response time — 2 seconds). Typical event duration is only five to ten minutes and participants can nominate specific facility loads to participate (i.e., the entire customer facility does not need to be curtailed). This program pays for availability. Customers are paid €8.20/MWh that is available for curtailment between 7am and midnight.[li]

9. GERMANY

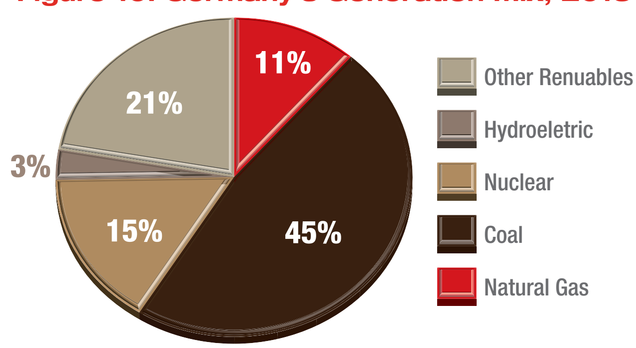
More so than any other jurisdiction in this survey, Germany has witnessed a dramatic change in the make-up of its generation mix in the last 20 years. A strong pro-renewables policy has led to enormous investment in wind and solar power in Germany — by the end of 2013, approximately 20 per cent of Germany's installed generating capacity was wind-powered and a further 20 per cent was solar-powered.

The remainder of Germany's generating capacity is provided by nuclear, natural gas, and, increasingly, coal. Following the events at Fukushima in 2011, the German government ordered eight German reactors to be shut down immediately, with the remaining nine to be phased out by 2020. Combined with a drop in American demand for European oil (due to falling North American natural gas prices), this has resulted in nearly half of Germany's electric energy now being generated by coal (see below).

Due to jurisdictional idiosyncrasies and the language barrier, for Navigant's analysis of German industrial rates, it has relied more heavily on secondary sources (e.g., European statistics, newspaper articles) to develop an understanding of the costs faced by industrial customers in Germany, and the drivers of those costs.

Table 32 reproduces the part of the Table ES-1 relevant to Germany, summarizing certain key features of this jurisdiction.

Figure 10. Germany's Generation Mix, 2013



Source: Statistisches Bundesamt

Table 32. Summary of Germany

Entity Name	Jurisdiction	Optional rates or System-Driven Incentives	Economic Development Rates	Competitive Energy Suply	Average Res : Ind. Ratio
N/A	Germany		✓		2.4
Source: Navigant analysis					

[xlix] EirGrid, Winter Peak Demand Reduction Scheme, October 2012, http://www.eirgrid.com/media/Presentation%20for%20WPDRS%20workshop_15%2010%202012.pdf.
[l] EirGrid, PowerSave Scheme Rules 2013/2014, August 2013, http://www.eirgrid.com/media/Powersave%20Scheme%20Rules%202013_2014.pdf.
[li] IBEC, Irish Energy Costs Seminar: The Power System and Demand Side Participation, June 2014, http://www.ibec.ie/IBEC/DFB.nsf/vPages/Energy~Resources~presentations---ibec-energy-event,-12-june-2014-12-06-2014/$file/The+power+system+and+demand+side+participation+-+Martin+McCarthy,+EirGrid.pdf.
[lii] DEWI GmbH, Statistics Germany http://www.dewi.de/dewi/index.php, German Solar Industry Association, Statistic data on Germany, April 2014, http://www.solarwirtschaft.de/fileadmin/media/pdf/2013_2_BSW-Solar_fact_sheet_solar_power.pdf. U.S. Energy Information Administration, International Energy Statistics, http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=2&pid=2&aid=7. Note: EIA data runs only from 2007 through 2011. Data for 2013 extrapolated using a linear trend.

This chapter is divided into the following sections:

- Industrial Costs Summary Table
- Detailed Discussion of Costs and Cost Drivers

Industrial Costs Summary Table

A high-level summary of Navigant's findings for Germany are shown in Table 33.

Note that in the table below, there is some discussion of taxes imposed as part of the German Renewable Energy Act. Following convention, this will be referenced using the German acronym: EEG. The tax is known as the "EEG surcharge".

Table 33. Summary of Germany Industrial Rates

Germany					
Average Cost of Electricity (Eurostat Survey of Invoices)					
	Residential	Industrial			
Annual Energy (MWh):	2.5–15	500–2,000	2,000–20,000	20,000–70,000	70,000–150,000
Total unit cost (€/kWh):	0.28	0.14	0.13	0.11	0.10
Res/Ind Ratio	1.00	1.97	2.24	2.55	2.93
Average Electricity Cost (Eurostat)					
Commodity (Generation):	0.5–2 GWh/Year 2–20 GWh/Year 20–70 GWh/Year 70–150 GWh/Year		€ 0.061 /kWh € 0.056 /kWh € 0.049 /kWh € 0.049 /kWh		
	Typically purchased directly from the wholesale market (EEX).				
Network Fees (Dx and Tx):	0.5–2 GWh/Year 2–20 GWh/Year 20–70 GWh/Year 70–150 GWh/Year		€ 0.030 /kWh € 0.024 /kWh € 0.013 /kWh € 0.013 /kWh		
	Customers pay both a demand and energy charge that varies by voltage level. Rates driven by system average (not marginal) costs. Dx and Tx charges are flat (do not vary by time of day).				
Taxes and Leveies:	0.5–2 GWh/Year 2–20 GWh/Year 20–70 GWh/Year 70–150 GWh/Year		€ 0.054 /kWh € 0.048 /kWh € 0.035 /kWh € 0.035 /kWh		
	Certain enrgy-intensive industries qualify for total reimbursment of all non-EEG electricity taxes. Industrial customers with annual consumption of > 1 GWh elegible to receive discount on EEG surcharge (6.24 Euro ¢/kWh) of between 90% and 99% (depending on annual volume).				
Demand Response					
Demand Response:	Demand response is currently very limited in Germany with only "innovation projects" (i.e. pilots) currently offering traditional peak demand response, as well as ancillary services. Note: Germany's very high investment in renewables means that significant interest exist in "negtive" DR — that is the ability of loads to increase (as well as decrease) load in response to system requirements.				

Detailed Discussion of Costs and Cost Drivers

Commodity (Generation) Costs

Although Navigant has not been able find any English-language documents that clearly outline industrial customer tariffs in Germany, it is apparent that large industrial customers purchase power directly from the wholesale market,[liii] presumably paying a real-time (or day-ahead) price for energy.

Wholesale prices in Germany, particularly during the system peaks, have been falling since 2011 due to changes

[liii] *Camus, Gabriel The stolen fruit of the Energiewende: German suppliers are not passing on lower wholesale prices to consumers, Energy Post, May 2014, http://www.energypost.eu/stolen-fruit-energiewende-electricity-suppliers-taxation-responsible-high-prices/.*

[liv] *The Economist, "How to lose half a trillion euros", October 2013, http://www.economist.com/news/briefing/21587782-europes-electricity-providers-face-existential-threat-how-lose-half-trillion-euros.*

in supply — in 2011, the average wholesale price of electricity in Germany was as high as € 60/MWh, whereas in 2013 it had fallen to well below € 40/MWh.[liv] This is due to the greatly increased renewable capacity available at very low marginal cost, as well as to the coincidence of solar generation's peak capacity with system summer peak demand.

These lower wholesale prices have driven down the price of electricity for industrial customers participating in the market or with reasonable bargaining power. The lower cost of energy and supply has not flown through to residential rates, however, due to a lack of competition and "sticky" retail rates. Although nominally competitive, the four largest competitive electricity suppliers in Germany (E. ON, RWE, EnBW, and Vattenfall Europe) cover only 40 per cent of the distribution market, with distribution in the regional markets dominated by local suppliers ("Stadtwerke").

Industrial customers pay on average approximately 30 per cent–40 per cent less than residential customers for the commodity portion of the electricity they consume, depending on annual consumption levels.

Network Fees (Dx and Tx)

Navigant was able to uncover precisely what rates apply to industrial customers, and determined that transmission and distribution charges are made up of both a demand and an energy charge, that charges vary by customer voltage level, but not geographic location, and that charges are based on average (not marginal) system costs. Navigant was also able to determine that distribution charges are flat and do not vary by time of day (as they do, for example, in California).[lv]

Industrial customers pay on average approximately 50 per cent-80 per cent less than residential customers for the transmission and distribution portion of the electricity they consume, depending on annual consumption levels.

Taxes and Levies

A significant driver of the low cost of electricity consumption by industrial customers, relative to the cost for residential customers, is the rate at which these two different types of customer are taxed for their electricity use. According to Eurostat, residential customers pay an average of more than 14 Euro ¢/kWh in taxes. This is approximately three times as much as is paid by industrial customers.

Two factors drive this result: German tax law, and the German Renewable Energy Act (EEG) surcharge.

Under Germany's electricity tax law of 1999, industrial customers belonging to energy-intensive sectors are eligible for a complete reimbursement of non-EEG-related energy taxes. The sectors covered by this law include those responsible for glass, ceramic, cement, metal, fertilizer, and chemical production, as well as those requiring significant amounts of electrolysis.[lvi]

As noted above, non-hydro renewable energy generation has experienced enormous growth in Germany over the last ten years. This is the result of an explicit and legislated policy direction of the German government. This growth has in part been financed by an EEG surcharge that is currently fixed at 6.24 Euro ¢/kWh. For context, this is approximately three quarters the amount that residential customers pay for energy and supply.

Many industrial electricity customers are permitted to pay a highly discounted EEG surcharge, which is known as the Umlage. This discount is offered as part of an explicit policy position on the part of the German government to preserve German jobs, or, as Germany's Federal Minister for Economic Affairs and Energy put it: "…energy transitions cost money [but]… we must ensure that our industry remains competitive."[lvii]

The discount for which a customer is eligible is a function of total annual consumption, as outlined in Table 34.

Table 34. EEG Surcharge Discounts for Industrial customers

Annual Consumption	EEG Surcharge Discount
1-10 GWh	90 % of standard EEG rate (6.24 Euro ¢/kWh)
>10 – 100 GWh	99% of standard EEG rate (6.24 Euro ¢/kWh)
>100 GWh	99.5% of standard EEG rate (6.24 Euro ¢/kWh)
Source: Agora Energiewende	

Industrial customers pay on average approximately 60 per cent–75 per cent less than residential customers in taxes and levies for electricity they consume, depending on annual consumption levels.

[liv] *The Economist, "How to lose half a trillion euros", October 2013, http://www.economist.com/news/briefing/21587782-europes-electricity-providers-face-existential-threat-how-lose-half-trillion-euros.*
[lv] *Petrov, Dr. Konstantin and Keller, Dr. Katja, Network Pricing Models in Europe – From Normative Principles to Practical Issues, 2009 http://www.dnvkema.com/Images/Network%20Pricing%20Models%20in%20Europe.pdf*
[lvi] *European Commission, Energy prices and costs report SWD(2014) 20 final/2, March 2014, http://ec.europa.eu/energy/doc/2030/20140122_swd_prices.pdf.*
[lvii] *EurActiv, EU warned 'do not play with fire' over energy rebates for German Industry, March 2014, http://www.euractiv.com/sections/industrial-renaissance/eu-warned-do-not-play-fire-over-energy-rebates-german-industry.*

10. CONCLUSIONS

The principal finding of Navigant's survey of industrial rates is that **compared to a large number of other North American utilities, the relative cost of electricity to industrial customers in Nova Scotia is quite high.**

Based on this initial finding, Navigant conducted a detailed survey of eight different jurisdictions in which the average cost of electricity to industrial customers is, relative to the average cost of electricity to residential customers, quite low. In surveying these jurisdictions, Navigant has conducted a detailed analysis of the industrial electricity rates offered in these jurisdictions, and the components that drive the overall cost of electricity for industrial customers.

After a detailed examination of these eight jurisdictions, Navigant concluded that their more competitive industrial electricity costs may be driven by one or more of the following three factors:

1. Electricity rates are used as a tool by to support a policy of economic development and job growth, as well as to support the global competitiveness of local industry. For example:

   a. In Pennsylvania, PECO offers an economic development tariff that requires customers to demonstrate (via tax filings of employee payroll) specific levels of job increases for each additional MW of load, as well as requiring LEED[lviii] certification of new facilities or the development of brownfield sites.[lix]

   b. In California, Pacific Gas and Electric offers incremental discounts to eligible customers that are located in cities or counties in which the unemployment rate is 125% of the state average.

   c. In Germany, large industrial customers receive very steep discounts (up to 99.5%) on a renewable energy surcharge (6.24 Euro ¢/kWh) to protect employment and industry competitiveness.

2. Utilities offer industrial customers flexible pricing options tied to the provision of system benefits that reduce costs for all customers. Utilities understand that industrial customers are not a homogenous group and that a "one-size-fits-all" approach fails to capture the value that large industrial customers have to offer the electricity system. This can take the form of optional tariffs, rate riders, and demand response[lx] programs, all of which allow industrial customers to reduce their effective cost of electricity and benefit all ratepayers by reducing overall system costs. For example:

   a. In Iowa, MidAmerican Energy offers industrial customers the options of (TOU)[lxi] pricing (more suitable for lower load factor customers than the standard rate), a foundry-specific interruptible TOU tariff[lxii] designed to optimize arc furnace operation to system costs, and three other demand response or interruptible rate riders, each with different levels of risk to the customer and serving different purposes in reducing system costs.

   b. In California, Pacific Gas and Electric offers four different demand response programs, some intended principally for economic dispatch, others for emergency and reliability dispatch.[lxiii] These programs run from the very low-risk (e.g., bill protection for the first year, nominated firm loads) to the much higher risk (e.g., noncompliance results in fines of up to $14/kW), and are intended to provide opportunities for all industrial customers to provide value to the electricity system.

   c. In Ireland, EirGrid, the system and market operator, offers four different demand response programs to large industrial customers, including the opportunity for customers to bid into the capacity market, a short-term auto DR program,[lxiv] and a more traditional large industrial DR program.

3. Base electricity rates tend to more closely reflect the costs that customers contribute to the system, in particular the fixed costs of peaking generation. For example:

   a. In Pennsylvania, industrial customers purchasing their electricity directly from their utility (as opposed to from a competitive supplier) pay a commodity[lxv] demand charge that is solely determined by their contribution to overall system peak. A customer's peak demand charge is based entirely on that

lviii Leadership in Energy and Environmental Design (LEED) is a building rating system developed by the U.S. Green Building Council.
lix Sites previously used for industrial purposes that may be contaminated by low levels of hazardous waste. Development of these sites requires soil remediation, which can significantly increase costs.
lx Demand response, or DR, refers to the practice of reducing total system load at peak times by curtailing (shutting down) customers with large loads.
lxi Time-of-use electricity rates are rates that vary by time of day. For example, customers may be subject to one demand charge ($/kW) from 8am to 8pm on non-holiday weekdays (a "peak" period) and another, much lower, charge for demand occurring from 8pm to 8am or on weekends and holidays.
lxii An interruptible tariff or rate is analogous to a DR program – typically, customers exchange the right of the utility to interrupt service for a reduction in rates.
lxiii "Economic dispatch" refers to the practice of using DR resources when the marginal cost of generation exceeds that of using the DR resource.
lxiv "Auto DR" refers to a demand response program in which the participant (an industrial customer) allows the utility or system operator to automatically interrupt that customer's load without warning.
lxv The generation cost of electricity, distinct from transmission and distribution charges.

customer's load in the peak hour of the top five system demand days.

b. In California, customers electing to receive their supply at transmission voltage receive a substantial discount on commodity and distribution and transmission charges, up to $4/kW (~15%) for commodity demand charges and up to $12/kW (~80%) for distribution and transmission demand charges.

c. In Ontario, Class A customers (those with peak demands greater than 5 MW) pay for the Global Adjustment component of their commodity demand charge based on their demand in the peak hour of the top five demand days experienced by the Ontario electricity system.

It is important to note that NSPI does currently offer an interruptible an interruptible rider for its largest industrial customers (2,000 kVA or 1,800 kW and up). This rider provides a discount of approximately 25% per kVA per month for the nominated interruptible demand (the difference between contracted firm and total billing demand). Participants are required curtail the required load within ten minutes of interruption event initiation and are subject to penalties of between $15 to $30 per kVA of required load not curtailed.

NSPI also offers an optional real-time pricing tariff. Under this tariff customers are charged NSPI's actual hourly marginal costs, plus a volumetric (per kWh) adder of between 8 and 11 cents (depending on voltage) during the 16 hours between 7am and 11pm on weekdays, and between 0.6 and 3 cents in all other hours.

In Table 35, a brief summary of the findings for each entity and/or jurisdiction surveyed is provided. This table indicates the following:

- Whether the surveyed entity or jurisdiction offers customers optional rates or system-driven incentives, to take advantage of industrial customers' flexibility to reduce system costs in a variety of ways
- Whether the surveyed entity or jurisdiction offers economic development rates (also known as load retention or attraction tariffs) that are explicitly designed to increase employment or protect the competitiveness of energy-intensive industries
- Whether the surveyed entity or jurisdiction is deregulated (also known as "Open Access" in the U.S.), meaning that customers have many options for contracting energy supply, resulting in commodity prices that closely reflect (or are identical to) wholesale electricity prices
- The average ratio of residential unit electricity cost to industrial unit electricity cost

Table 35. Summary of Surveyed Entities and Jurisdictions

Entity Name	Jurisdiction	Optional rates or System-Driven Incentives	Economic Development Rates	Competitive Energy Suply	Average Res : Ind. Ratio
Pacific GAs and Electric (PG&E)	California	✓	✓		2.3
Southern California Edison (SCE)	California	✓	✓		2.4
MidAmerican Energy — South System	Iowa	✓	✓		2.2
Interstate Power and Light (IPL)	Iowa	✓	✓		2.1
Duquesne Light Company	Pennsylvania	✓		✓	1.9
Pennsylvania Electtric Company (PECO)	Pennsylvania	✓	✓	✓	1.6**
PJM Interconections	13 states and D.C.	✓		✓	2.0
Entergy Texas	Texas	✓			2.0
N/A	Ontario	✓	✓		2.0
N/A	Ireland	✓	✓	✓	2.0
N/A	Germany		✓		2.4
Noiva Scotia Power Inc.*	Nova Scotia	✓	✓		1.4

** NSPI offers large industrial customers an Interruptible Rider that offers a discount as an incentive to participationand also offers and optional real-time rate. NSPI does offer a load retention tariff but it s tariff book does not specify the discount offered or to how many customers it may be offered.*
*** Average of all utilities surveyed by EEI located in states in which PJM has a presence*
Source: Navigant analysis

11. GLOSSARY

TOU:	Acronym for "time-of-use" electricity rates. TOU rates are those in which customers are charged a different amount based on the time of day, season, and/or day of the week. Charges may be either energy-based ($/kWh) or demand-based ($/kW).
Commodity [charge, rate, etc.]:	Refers to the component of customer electricity cost attributable to the fixed and fuel (variable) costs of generation.
Distribution charge:	Refers to the component of customer electricity cost attributable to the cost of building and maintaining the distribution network that provides electricity to most consumers.
Transmission charge:	Refers to the component of customer electricity cost attributable the cost of building and maintaining the network of high-voltage transmission lines for transporting electricity from generators to distribution networks.
Auto-DR:	Generally refers to a DR program (see below) in which participants cede control of their system to the program administrator (e.g., the utility). This means that the participant's power can be interrupted directly by the program administrator without first informing the participant.
DR:	Demand response. DR refers to the practice of managing system peak loads by curtailing large individual customers or groups of customers. DR programs tend to be very similar to interruptible load tariffs – in general, participants are rewarded for reducing demand when called upon to do so by the utility, system operator or other relevant authority.
Bundled price:	Refers to the total volumetric cost of electricity ($/kWh), including commodity, transmission, distribution, and other relevant charges.
$/kW-year:	Refers to a capacity payment (as opposed to an energy payment of $/kWh). The magnitude of the payment in order of a kW of capacity to be available to the given authority for a calendar year.
Aggregator:	An organization provides DR capabilities to a utility, system operator or other authority. The aggregator contracts with individual electricity customers to provide it with DR capability. Effectively, a middleman between electricity customers offering DR and the utility, system operator or other authority requiring it.
CPP:	Critical peak pricing. In exchange for lower rates in most other time periods, customers agree to pay a very high price for electricity in a small number of non-scheduled "critical" periods (generally fewer than 100 hours per year).
RTP:	Real-time pricing. Electricity prices fluctuate hourly, based on market-clearing conditions.
PJM:	PJM Interconnection is a regional transmission organization and independent system operator that coordinates a wholesale electricity market across 13 states and the District of Columbia. PJM is responsible for running the auctions that set the prices for energy, capacity, ancillary services, and transmission rights, among others.

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