Imperial Irrigation District

Transmission Rate Options Study

January 2012

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1. Introduction

The Imperial Irrigation District (IID) provides electric power at retail to all of Imperial County and portions of Riverside County (to the north of Imperial County) and San Diego County (to the east of Imperial County). IID also provides transmission service under its Open Access Transmission Tariff (OATT) to generators located within its service area and entities using the IID transmission system to move power into, out of, or through the IID service area on high-voltage transmission lines owned by IID. With the passage of S.B. 2 (1X), California electric utilities are required to provide their electric customers with electric power that includes at least 33 percent of renewable energy by 2020, as defined in the act. This requirement has resulted in substantial amounts of new, renewable generation development in the State. Given the quality of renewable resources in the IID footprint, Imperial County and portions of adjacent counties can achieve economic benefits (higher tax revenues, increased employment, and increased income) with the development of new, renewable energy projects. These benefits are particularly important to Imperial County due to depressed local economic conditions.

Among the barriers to renewable project development in the IID service area has been the cost of interconnection and the costs of wholesale transmission. This analysis addresses potential methods that may be available to IID to reduce those costs to renewable energy developers and hence reduce the impediments to renewable energy development in Imperial County.

Prior to the start of this analysis, IID personnel conveyed certain constraints which reflect the policy positions and financial circumstances of the Company. Chief among these are:

- IID cannot use any accumulated reserves to fund, in whole or in part, either the interconnection costs or the wholesale transmission costs of renewable generators;
- IID cannot rely on increasing its debt obligations to fund, in whole or in part, either the interconnection costs or the wholesale transmission costs of renewable generators;
- IID is not willing to reduce either interconnection costs or wholesale transmission costs through a cross-subsidy arrangement that entails subsidies from the residential class; and
- IID must recover its full cost of service.

Exeter Associates, Inc. was asked to identify and examine options that may be available to IID to make renewable energy project development within the IID service area more attractive to potential renewable energy project developers while at the same time avoiding cross-subsidies from the residential class and ensuring full cost recovery from the aggregate of IID's ratepayers. Exeter has identified three potential avenues by which IID may accomplish its goals. Two of the three approaches relate to reductions in wholesale transmission costs and are explained in detail in this report, including the financial implications of these two approaches. The remaining approach involves local governments and Exeter has been asked to address this third option only at the conceptual level. The third approach, that is, the approach involving local government, entails an overall reduction in developer costs unrelated to interconnection or wholesale transmission costs directly.

The first two approaches entail IID implementing an economic development rate that would serve to reduce the costs of transmission to new, renewable project developers. The second approach entails direct subsidization of new project development by retail customers. The financial implications of these two arrangements are identical, though important implementation and operational differences are discussed.

The third approach entails cultivating a partnership with the counties within the IID service area to devise an incentive program in the form of reduced tax obligations for developers meeting certain specified qualifications. This approach would allow IID to leverage any incentive arrangement related to wholesale transmission tariffs that it may implement.

Section 2 of the report documents the current arrangements. Section 3 of this report discusses the three options identified. Section 4 contains important conclusions and recommendations.

2. Current Arrangements

IID establishes "open seasons," which typically run for six months, during which time energy project developers may indicate interest in project development in the defined cluster. The developer then executes a Transmission Service Agreement with IID, which requires a security deposit on the part of the developer. Following system planning and the determination of system upgrades to accommodate the new generation, the developer enters into a Generation Interconnection Agreement (GIA), which stipulates the upgrades required, costs, cost coverage responsibilities, and entitlement to transmission rate credits.

The open season arrangement established by IID facilitates several individual and independent projects being able to minimize the total costs of interconnection by sharing the

costs among the participating projects. This arrangement is in lieu of independent developers simply notifying IID serially, thus necessitating IID to continually revise the interconnection cost estimates and perhaps redesign the interconnection facilities to accommodate multiple projects. As a consequence, the open season arrangement, to the extent that it operates as designed and intended, provides benefits to both the developers and to IID.

Interconnection costs are repaid over time as the developers use and pay for the IID transmission system. Currently, the maximum payback period is 25 years but is established on a project-by-project basis and agreed to between the parties.

Transmission rates are established through the District's revenue requirements and class cost-of-service methodology. Cost coverage for transmission-related costs is based on peak demand.[1]

3. Methods for Potential Reduction of Interconnection and Transmission Costs to Renewable Generators

3.1 Interconnection Costs

The method adopted by IID to mitigate interconnection costs to new renewable generators is similar to the approach used elsewhere, and has been subject to some of the same difficulties as experienced elsewhere. In particular, following the expiration of the open season, project developers that have identified a particular project for development often reverse course and withdraw the project. Withdrawal can occur for a variety of reasons including the inability to obtain financing (which often rests on the developer's ability to secure a Purchased Power

[1] In its analysis, R.W. Beck examined the implications of basing the transmission rates on a 50/50 split between energy and demand and also 100 percent on energy in lieu of the current arrangement which relies on a 100 percent demand allocator. We note that some renewable energy projects with low capacity factors (e.g., solar) benefit from an increasing portion of the transmission cost placed on energy whereas renewable projects with higher capacity factors (e.g., geothermal) pay higher rates under an allocation more heavily weighted on energy.

Agreement from a credit-worthy counterparty), identification of a more economically attractive project elsewhere, or changes in market conditions (or the developer's assessment of market conditions) affecting the overall viability and profitability of the project. This presents logistical and planning difficulties for IID similar to those experienced elsewhere. Exeter is unaware of any effective solution to this problem that does not entail additional burdens being placed on the developers, which is counter-productive to IID's overarching goals. For example, increased levels of up-front funding could be required with forfeiture of deposits if the project is cancelled. The imposition of these kinds of conditions would potentially ease IID's logistical and planning difficulties, but they also make the IID service area less attractive for project development.

The general approach employed is judged to be conceptually sound and beneficial to both developers and IID. Developers get the benefit of sharing interconnection costs with the other projects in the cluster while IID (at least conceptually) benefits from being able to plan transmission system modifications to accommodate the cluster in aggregate rather than have to employ a piecemeal approach.

One method to potentially reduce the adverse affect on renewable development created by developer interconnection costs is to revise the treatment of the interconnection costs to developers that seek to develop projects after network upgrades have been completed. Currently, the first entrant must bear the cost of the network upgrades and there is no mechanism in place to facilitate assignment of existing network costs to the new entrant. The costs to existing developers could be reduced through payments from the new entity to cover a pro-rata portion of the cost of facilities paid for by the initial developers. This is a common practice in line extension policies to serve new users. The initial user bears the cost of the extension (usually

above some standard allowance). As future customers connect to that extension, this initial user is repaid for a portion of the cots from the amounts collected from subsequent customers.

3.2 Economic Development Rates/Subsidies

3.2.1 Introduction

An economic development rate is a mechanism offered by the utility to reduce operating costs to new or expanding businesses within the utility service area. Economic development rates can be used as a utility-sponsored method to promote local business development and attract businesses to the local area that may have chosen to locate elsewhere absent the financial incentive provided by the rate.

An attractive feature of economic development rates is that the utility can exercise control over the magnitude of its commitment, the types of projects/businesses that are eligible to receive favorable rate treatment, and the duration of the utility commitment. The utility can also require those customers applying for the rate to demonstrate the degree to which the customer's expanded operations (or new location within the service area) positively affects the local community, including such factors as tax revenues going to the local jurisdiction, employment impacts, infrastructure development, and economic multiplier effects (that is, secondary and higher round economic impacts).[2]

There are two major disadvantages to economic development rates. First, the rate reductions provided in the form of economic development rates must be paid for by other utility customers. By definition, this entails certain customer classes providing a subsidy to the

[2] A rough estimate of multiplier impacts is that each dollar directly expended by a business (or government project) will result in an additional dollar of expenditures in subsequent spending rounds. The precise value of the multiplier depends on numerous factors including the degree to which the business relies on local goods and services, the capital intensiveness versus labor intensiveness of the operation, and the absolute level of wages.

customers receiving the benefit of reduced rates. Those customers funding the subsidy will benefit through either reduced local taxes or expanded local services, additional employment opportunities, and higher levels of local economic activity. The benefits, however, are not easily measured on a per-customer basis, in contrast with the easily calculable and identifiable per-customer subsidy costs.

The second disadvantage, inherent in many incentive programs, is free-ridership. Certain customers may qualify for an economic development rate but the availability of the more favorable rate does not actually induce any change in the actions of the customer. For example, a firm may take advantage of an available economic development rate but would have located in the target area even if no economic development rate had been offered. There is no easy or precise way to assess the degree to which free-ridership is occurring but the degree of free-ridership can be mitigated through a carefully crafted eligibility requirement contained in the economic development rate and through careful review of application of customers for acceptance.

3.2.2 Economic Development Rates of Other Utilities

Utility-sponsored economic development programs are generally offered in two ways:

1. The utility incurs the costs associated with economic development programs in its service territory (discounted electric rates to new customers or customers that are expanding their business establishments) and passes those costs on to customers through a tariff rider or surcharge. This approach, discussed below, is employed by the Dayton Power and Light Company (Ohio).

2. The costs associated with the utility-offered economic development rates are allocated among existing customers through base rates. This approach, also discussed below, is employed by Redding Electric Utility and Progress Energy Carolinas, Inc.

Dayton Power and Light Company. In October 2011, the Public Utilities Commission of Ohio (PUCO) approved an Economic Development Cost Recovery Rider (EDCR) for the Dayton Power and Light Company (DP&L). The EDCR allows DP&L to recover costs incurred as a result of economic development and job retention programs. The EDCR is assessed as a per-kWh charge, which varies based on customer class – the residential rate is $0.0007454/kWh. The EDCR will be assessed until DP&L's costs are fully recovered and may be revised up to twice per year subject to PUCO approval. Additionally, the customer applying participation in the economic development and job retention program must identify the economic benefits accruing to the local area before being granted access to the more favorable rate. A copy of DP&L's EDCR is included in Attachment A.

The Redding Electric Utility. The Redding Electric Utility (REU), a Northern California municipal utility, offers two types of economic development discounts to new or expanding electric customers to attract new business into the Redding region. These discounts include Economic Development Service (EDS) and Economic Attraction Service (EAS). In order to receive either service a customer must apply for the relevant service within one year of becoming eligible for that service.

EDS is applicable to: (1) any new customer whose monthly maximum demand is expected to exceed 100 kW for three months out of a consecutive 12-month period or: (2) any

existing customer whose monthly maximum demand is expected to increase by 100 kW for three months out of a consecutive 12-month period. A new customer is defined as a new business bringing an entirely new electric load into the REU service territory. Customers receiving EDS are provided with discounted electric rates for five years (i.e., 60 billing cycles) that decrease linearly over the course of the five-year period:

- Year 1 (Billing cycle 1 through 12) = 25%
- Year 2 (Billing cycle 13 through 24) = 20%
- Year 3 (Billing cycle 25 through 36) = 15%
- Year 4 (Billing cycle 37 through 48) = 10%
- Year 5 (Billing cycle 49 through 60) = 5%

Note that REU requires the customer to sign a five-year contract. In addition, REU's tariff stipulates that under no circumstances shall the cost of power to the customer fall below REU's average cost to supply power to that customer.

Economic Attraction Service (EAS) is applicable to any new customer who is considered a manufacturing or industrial company, and who is expected to use at least 15,000 kWh per month for three months out of a 12-month period. Note that EAS is not intended for customers in retail sales. Under this service, the customer and the REU Director negotiate a mutually agreed upon rate that will include all costs of serving the customer. To receive EAS, the customer is required to sign a contract, the length of which is negotiable. REU's tariff stipulates that in no event shall the cost of power to the customer fall below the incremental cost of power to REU calculated on a per-kWh basis. A copy of REU's EDS and EAS schedules are in included in Attachment A.

Progress Energy Carolinas. In North Carolina, the Carolina Power and Light Company (doing business as Progress Energy Carolinas, Inc.) offers economic development discounts to new or expanding electric customers. The Economic Development Rider (EDR) is only available for nonresidential establishments that receive service under the Large General Service or Large General Service Time-of-Use schedules. In order to qualify for service under the EDR, the new load must be a minimum of 1,000 kW and the customer must meet one of the following qualifications:

1. The business must employ an additional workforce in the utility's service area of at least 75 full-time equivalent employees; or
2. The new load must result in capital investment of $400,000, provided that such investment is accompanied by a net increase in full-time equivalent employees employed in the utility's service area.

In order to receive service under the EDR, a customer must submit an application to Progress Energy affirming that the availability of the EDR was a factor in customer's decision to locate the new load in Progress Energy's service territory.[3] In addition, the customer must agree to a minimum contract term of five years.

The economic development discount is calculated on a per-kW basis. The new load (kW) is multiplied by a discount rate (in dollars) which is determined by the customers load factor and the number of months that services have been rendered under the EDR. See Progress Energy Carolinas EDR Tariff in Attachment A for specific discount rates (Sheet 3). The

[3] This requirement is designed to eliminate free-ridership.

economic development discount equals zero if the customers load factor is less than 40 percent or after five years (i.e., 60 billing cycles) of service under the EDR.

The examples provided above are applicable to retail electric service customers rather than transmission service customers as would be the case if IID were to implement an economic development rate. The examples indicate, however, the wide range of eligibility requirements and restrictions that have been included in economic development rates as a means of:

- Ensuring that the utility is not exposed to greater costs than are acceptable;
- Specifying the types of customers that are eligible for participation;
- Minimizing the potential for free-ridership; and
- Limiting the duration of the availability of the discounted rate.

In the case of REU's Economic Attraction Service, many aspects of the agreement are negotiated and hence can be tailored to the specific circumstances of the customer. This arrangement provides extensive latitude to the Utility on a customer-by-customer basis.

Table 1, below, shows which California utilities currently have in place an economic development rate.

Table 1 Economic Development Rates (or Similar) in Place in California	
California Electric Utility	**Economic Development Rate/Rider**
Alameda Municipal Power	ED: Economic Development Incentive Discount
Anaheim Public Utilities	DEV-EDBR: Developmental Economic Development/Business Retention
Anza Electric Coop	None
Azusa Water & Light	Economic Development Rate - Schedule EDR
City of Palo Alto Utilities	None
City of Corona Water & Power	None
Bear Valley Electric	None
Burbank Water & Power	None
Colton Public Utilities	None
Glendale Water & Power	None
Healdsburg Municipal Electric Department	None
IID	None
LADWP	General Service Rider EZ - Enterprise Zone
Lassen MUD	None
Lodi Electric Utility	None
Merced Irrigation District	None
Modesto Irrigation District	Economic Development Discount Provision
Mountain Utilities	None
Pacific Power	None
Pasadena Water & Power	None
PG&E	None
Plumas-Sierra REC	None
Redding Electric Utility	Economic Development Service
Riverside Public Utilities	Schedule ED: Economic Development Rates – Attraction And Expansion
Roseville Electric	None
SMUD	None
Silicon Valley Power	None
SDG&E	None
SCE	Schedule EDR-A: Economic Development Rate-Attraction Schedule EDR-E: Economic Development Rate-Expansion Schedule EDR-R: Economic Development Rate-Retention
Surprise Valley Electric	None
Truckee Donner PUD	None
Turlock Irrigation District	None
Ukiah Utilities	None
Vernon Light & Power	None
Valley Electric Association	None

3.2.3 An IID Economic Development Rate

To address the implications of an economic development rate for IID, we examined several options that entail different rates (based on alternative cost allocation methodologies explored in the R. W. Beck letter report to IID dated August 19, 2011), considered the impacts to different types of renewable energy developers (geothermal and solar), and developed two alternative cost coverage approaches. The two alternative approaches are a tariff rider that includes residential, commercial, industrial, agricultural and public authority customers and a second that includes only commercial, industrial, agricultural, and public authority customers; that is, the second approach would not result in any of the economic development subsidy being provided by the residential class. In both sets of calculations, interdepartmental and street lighting sales were excluded.

If IID were to rely upon a direct subsidy approach, the figures would be identical to the economic development rate approach but would provide less flexibility to IID in structuring the arrangement.[4] The implementation issues are discussed following the presentation of the impacts.

The parameters and assumptions relied upon to calculate the impacts to ratepayers are shown in Table 2, below. Table 3 shows the cost impacts to developers associated with a 25 percent reduction in the wholesale transmission rates (separately for solar and geothermal resources) and under three possible cost allocation methods (i.e., 100 percent of costs allocated on demand; 50 percent allocated on demand and 50 percent allocated on energy; and 100 percent of wholesale transmission costs allocated on energy). Table 4 shows the customer cost impacts

[4] A direct subsidy would entail a category of wholesale transmission customers (e.g., new renewable generators) paying less than cost-of-service while other customer classes would pay in excess of 100 percent of the cost-of-service.

by class on a per-MWh basis. The figures shown in Table 4 are computed by dividing the amounts to be recovered from retail customers (from Table 3) by the sum of MWh retail sales (excluding interdepartmental use and lighting sales). Table 5 shows average annual costs per retail customer, computed as the dollars/MWh figures (from Table 4) multiplied by average annual MWh use per customer, by class (calculated from Table 2).

Table 2

Underlying Data Used to Estimate Economic Development Rate/Subsidy Impacts

Number of Customers	
Residential customers	113,252
Commercial customers	17,570
Industrial customers	19
Agricultural customers	800
Public Authority customers	1,022
Annual Class Consumption	
Residential MWh/year	1,544,289
Commercial MWh/year	1,445,976
Industrial MWh/year	5,455
Agricultural MWh/year	71,807
Public Authority MWh/year	72,604
Wholesale Transmission Rates	
Based on 100% Demand	$2.00/kW-Mo.
Based on 50% Demand/50% Energy	$1.00/kW-Mo. $1.97/MWh
Based on 100% Energy	$3.94/MWh

Table 3

Estimated Economic Development Rate/Subsidy Impacts

	Low Capacity Factor (Solar)[1]	High Capacity Factor (Geothermal)[2]
Wholesale Transmission Charges/year to Project Developer (Full Cost for a 150 MW project))		
100% Demand	$ 3,600,000	$ 3,600,000
50% Demand/50% Energy	2,447,145	3,870,864
100% Energy	1,294,290	4,141,728
Wholesale Transmission Charges/year to Project Developer (25% reduction from full cost for a 150 MW project)		
100% Demand	$ 2,700,000	$ 2,700,000
50% Demand/50% Energy	1,835,359	2,903,148
100% Energy	970,718	3,106,296
Amount to be Recovered from Retail Customers due to 25% Cost Reduction (Full cost charges minus charges reduced by 25%)		
100% Demand	$ 900,000	$ 900,000
50% Demand/50% Energy	611,786	967,716
100% Energy	323,573	1,035,432

[1] Solar is assumed to operate at a 0.25 annual capacity factor.

[2] Geothermal is assumed to operate at a 0.80 annual capacity factor.

Table 4

Estimated $/MWh to be Recovered from Retail Customers

	Cost Recovery For Low Capacity Factor Projects (Solar)[1]	Cost Recovery For High Capacity Factor Projects (Geothermal)[2]
Customer Recovery Classes Includes Residential		
100% Demand	$0.29	$0.29
50% Demand/50% Energy	0.19	0.31
100% Energy	0.10	0.33
Customer Recovery Classes Excludes Residential		
100% Demand	$0.56	$0.56
50% Demand/50% Energy	0.38	0.61
100% Energy	0.20	0.65

[1] Solar is assumed to operate at a 0.25 annual capacity factor.
[2] Geothermal is assumed to operate at a 0.80 annual capacity factor.

Table 5

Estimated Economic Development Rate/Subsidy Impacts
Average Annual Cost per Customer ($)[1]

	Including Cost Recovery from Residential Customers		Excluding Cost Recovery from Residential Customers	
	Low Capacity Factor (Solar)	**High Capacity Factor (Geothermal)**	**Low Capacity Factor (Solar)**	**High Capacity Factor (Geothermal)**
100% Demand				
Residential	$ 3.91	$ 3.91	--	--
Commercial	23.59	23.59	$ 46.41	$ 46.41
Industrial	82.29	82.29	161.92	161.92
Agricultural	25.73	25.73	50.62	50.62
Public Authority	20.36	20.36	40.06	40.06
50% Demand/50% Energy				
Residential	$ 2.66	$ 4.20	--	--
Commercial	16.03	25.36	$ 31.55	$ 49.91
Industrial	55.94	88.48	110.07	174.10
Agricultural	17.49	27.66	34.41	54.43
Public Authority	13.84	21.89	27.23	43.08
100% Energy				
Residential	$ 1.41	$ 4.50	--	--
Commercial	8.48	27.14	$ 16.69	$ 53.40
Industrial	29.58	94.67	58.21	186.28
Agricultural	9.25	29.60	18.20	58.24
Public Authority	7.32	23.43	14.40	46.09

[1] Calculated as the $/MWh to be recovered from Retail customers (from Table 4) times the average annual MWh per customer by class (Annual Consumption dividend by Number of Customers, both shown in Table 2).

As shown in Table 3, a 25 percent reduction results in meaningful benefits to both high capacity factor (geothermal) and low capacity factor (solar) wholesale transmission customers. A larger benefit to low capacity factor generators results from alternative cost allocation methodologies where greater proportions of total costs are allocated based on the transmission of energy rather than peak demand. For example, moving to a cost allocation scheme of 50 percent demand and 50 percent energy entails a decrease in total transmission costs for low capacity factor generators of approximately 32 percent (approximately $1.15 million per year) compared with a 25 percent reduction (e.g., the sample economic development rate/subsidy) of $900,000 per year under the cost allocation based purely on demand. The reverse situation exists for high load factor generators. The economic development rate/subsidy provides a reduction in costs; the alternative allocation methodologies relying on energy entail increases in costs (though the absolute value of the discount at 25 percent exceeds the absolute value of the increases related to the alternative cost allocation methods).

Shown on Table 4 are the additional costs per MWh to be recovered from the various customer classes to recover the discounted rate levels applicable to new, renewable generators. When residential customers are included in the overall pool of customers contributing to the discount coverage, the maximum cost per MWh is $0.33; when residential customers are excluded, the additional cost-per-MWh to cover the cost reduction to renewable generators is $0.65.

Table 5 shows the annual cost impact to the average customer in each of the affected classes. Where residential customers are assumed to contribute, the average residential customer would see a maximum annual increase of $4.50 (approximately $0.38 per month), which relates to the high load factor generator under a 100 percent energy allocation scheme. Under the 100

percent demand cost allocation methodology, annual cost increases to residential customers would be $3.91 for each type of generator at 150 MW of generation capacity (approximately $0.33 per month for each generation type). The largest annual increases would be for the average industrial customer, with annual costs approaching $100 under all three cost allocation methodologies where residential customers are included among the affected classes. Average costs approximately double to the non-residential classes when the residential contribution is removed.

As noted above, the cost impacts for an economic development rate and a direct subsidy arrangement are identical, though there are different characteristic of each one. The different characteristics allow for different implementation.

- The 25 percent discount used for the arithmetic example shown in Tables 3 through 5 can be set to decline over time (as is done by Redding Electric) under an economic development rate. This is more cumbersome under a direct rate subsidy arrangement.

- IID may have more latitude regarding wholesale transmission customer qualification for an economic development rate than under a direct subsidy.

- Limiting the total size of the subsidy arrangement may be more easily accomplished under the economic development approach than under a direct subsidy. For example, the economic development rate can easily be limited to the first 150 MW of solar generation and the first 100 MW of geothermal generation.

- Both arrangements can be suspended if circumstances warrant.

While either arrangement is workable, our view is that the greater latitude and flexibility under an economic development rate makes that approach more attractive.

3.3 Partnership with Local Governments

Given the fundamental goal of spurring local economic development, IID may want to consider engaging local government in providing certain incentives to new, renewable generators which, when coupled with incentives provided by IID, would make locating a new, renewable generation facility in the IID service area attractive to investors. For example, IID may consider entering into discussions with Imperial County, which represents the largest portion of the IID service area, to provide tax incentives to new, renewable power development. Such an arrangement would allow IID to reduce the rate discount offered, but provide an improved package which would include a County contribution. All entities would benefit from such an arrangement, including the County which would receive tax revenues that it may not otherwise garner.

We have not attempted to identify which taxes may be appropriate for the County to forgive, in part. Additionally, we have not explored the willingness of the County to engage in any discussions with IID on this issue. From IID's perspective, however, exploration of this option is low-cost and may provide a means for IID to leverage any wholesale transmission rate discounts that it deems appropriate.

4. Conclusions and Recommendations

Based on the foregoing analysis and discussion, we draw the following conclusions:

- Absent some form of subsidy from other customer classes, there does not appear to be any method by which IID can reduce its wholesale transmission rate and satisfy the "make whole" constraint.

- Of the two subsidization approaches addressed, the development of an economic development rate for wholesale transmission customers that will be developing new, renewable generation projects in the IID service area, appears to be more flexible and more easily limited than a direct subsidy approach.

- Substantial rate discounts (e.g., 25 percent) can be offered to new, renewable project developers with modest increases to IID's retail customers within the size limitations for new projects considered in this report.

- If residential customers are included in the pool of affected customers funding the wholesale transmission rate reduction, costs to residential consumers are well below $1.00 per month (on average). Rate increases to average customers in other classes are below $10.00 per month.

- The cost of subsidy funding to non-residential customers is approximately twice as high under all cost allocation arrangements if residential customers are excluded from the pool of affected customers. Overall subsidy coverage amounts, however, can be viewed as modest.

Based on these conclusions and information contained in this report, we make the following recommendations:

1. IID should further explore the potential to develop an economic development rate, with focus on achieving the best result (local economic development) for the least cost. IID should therefore investigate employment, income, and tax benefits associated with different types of renewable energy projects to ensure that any economic development rate offered would target the most beneficial development.

2. IID should engage in discussion with potential developers and research economic development rates in place elsewhere to better assess the magnitude of the rate discount needed to attract new projects.

3. IID should implement a mechanism that facilitates recovery of network upgrade costs by the developers that funded the upgrades when new projects relying on those upgrades come onto the network.

4. IID should engage Imperial County in discussions aimed at obtaining County-provided benefits to new project developers in a manner that leverages the wholesale transmission rate cost reductions being considered by IID.

ATTACHMENT A

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
ECONOMIC DEVELOPMENT COST RECOVERY RIDER

Ohio Law allows for the recovery of costs incurred as a result of economic development and job retention programs including foregone revenues. The rates and charges listed below are designed to recover the cost incurred in DP&L's service territory. The cost associated with these programs may change over time based on customer participation. The Economic Development Cost Recovery Rider shall be assessed on kilowatt-hours (kWh) of electricity per tariff class distributed under this Schedule at the rates stated below, effective on a bills-rendered basis in the Company's first billing unit for the month of November 2011.

Residential	$0.0007454	/kWh
Residential Heating - Rate A	$0.0007454	/kWh
Residential Heating - Rate B	$0.0007454	/kWh
Secondary	$0.0004422	/kWh
Primary	$0.0001605	/kWh
Primary-Substation	$0.0000613	/kWh
High Voltage	$0.0000618	/kWh
Private Outdoor Lighting		
9,500 Lumens High Pressure Sodium	$0.0331734	/lamp/month
28,000 Lumens High Pressure Sodium	$0.0816576	/lamp/month
7,000 Lumens Mercury	$0.0637950	/lamp/month
21,000 Lumens Mercury	$0.1309924	/lamp/month
2,500 Lumens Incandescent	$0.0544384	/lamp/month
7,000 Lumens Fluorescent	$0.0561396	/lamp/month
4,000 Lumens PT Mercury	$0.0365758	/lamp/month
School	$0.0002159	/kWh
Street Lighting	$0.0004390	/kWh

The Economic Development Rider Tariff shall be assessed until the Company's costs are fully recovered and may be revised twice a year subject to PUCO approval.

Filed pursuant to the Finding and Order in Case No. 11-4503-EL-RDR dated October 26, 2011 of the Public Utilities Commission of Ohio.

Issued October 28, 2011 Effective November 1, 2011

Issued by
PAUL M. BARBAS, President and Chief Executive Officer

ECONOMIC DEVELOPMENT SERVICE

APPLICABILITY

This service is applicable to any new customer whose monthly maximum demand is expected to exceed 100 kW for 3 months out of a consecutive 12-month period or to any existing customer whose monthly maximum demand is expected to increase by 100 kW for 3 months out of a consecutive 12-month period.

For the purpose of this service, a new customer is defined as a new business bringing entirely new electric load into the City. A business that changes location within the service territory or a business enterprise under new ownership does not qualify as a new business.

This service is not applicable to or available for resale, standby, or auxiliary service.

Qualified customers will be eligible for any and all service discounts available to commercial service customers including, but not limited to, the Primary/Transmission Service Discount and the Power Factor Adjustment.

EDS DISCOUNT

The monthly bill at the commercial rate, plus or minus any adjustments incorporated in this rate schedule or supplement hereto will be discounted as follows:

Discount:	Year 1	(Billing cycle 1 through 12)	= 25%
	Year 2	(Billing cycle 13 through 24)	= 20%
	Year 3	(Billing cycle 25 through 36)	= 15%
	Year 4	(Billing cycle 37 through 48)	= 10%
	Year 5	(Billing cycle 49 through 60)	= 5%

The Discount will end after 60 billing cycles.

In no event shall the cost of power to the customer fall below REU's average cost to supply power to that customer.

SPECIAL CONDITIONS

The customer will be required to sign a 5-year contract. If a customer covered under this schedule leaves before the expiration of the contract, penalties as established in the Council Policy regarding electric incentives for economic development shall apply.

A customer wishing to avail themselves of this service must apply for service within one year of becoming eligible, or lose that eligibility.

ECONOMIC DEVELOPMENT SERVICE **(continued)**

CHARACTER OF SERVICE

The service is characterized as single-phase or three-phase, 60 hertz, and at one standard nominal voltage as mutually agreed by REU and the customer and subject to availability at the point of delivery. All meter-recording equipment shall be supplied and maintained by REU. Any expense to modify the customer's facilities to accommodate the meter-recording equipment shall be paid by the customer.

ECONOMIC ATTRACTION SERVICE

APPLICABILITY

This service is applicable to any new customer who is considered a manufacturing or industrial company, and who is expected to use at least 15,000 kWh a month for three months out of a 12-month period. In addition, the Economic Attraction Service is not designed for those customers in a retail sales business.

Not applicable to, or available for, resale, standby, or auxiliary service.

CHARGES

A monthly bill will be provided at a rate mutually agreed upon by the company and the REU Director. This rate is negotiated and shall include all costs incurred in serving this customer. The rate shall include all relevant distribution and transmission-related costs, including fixed costs and power supply.

In no event shall the cost of power to the customer fall below the incremental cost of power to REU calculated on a per-kWh basis.

SPECIAL CONDITIONS

A customer on this schedule will be required to sign a contract. The length of the contract is negotiable. The intention of the Economic Attraction Service is to create a relationship with the customer, and for both parties to honor the terms of the negotiated contract. If, however, a customer covered under this schedule does not honor the terms of the contract, and leaves the REU system for another supplier, the customer may be required to pay a Competitive Transition Charge (CTC).

A customer who wishes to be serviced under this schedule must apply for service within one year of becoming eligible or lose that eligibility.

CHARACTER OF SERVICE

The service is characterized as single-phase or three-phase, 60 hertz, and at one standard nominal voltage as mutually agreed by REU and the customer and subject to availability at the point of delivery. All meter-recording equipment shall be supplied and maintained by REU. Any expense to modify the customer's facilities to accommodate the meter-recording equipment shall be paid by the customer.

ECONOMIC DEVELOPMENT
RIDER ED-9

AVAILABILITY

Available, only at Company's option, to nonresidential establishments receiving service under Company's Large General Service or Large General Service (Time-of-Use) Schedules provided that the establishment is not classified as Retail Trade or Public Administration by the Standard Industrial Classification (SIC) Manual published by the United States Government.

This Rider is available for load associated with initial permanent service to new establishments, expansion of existing establishments, or new customers in existing establishments who make application to Company for service under this Rider, and Company approves such application. The New Load applicable under this Rider must be a minimum of 1,000 kW at one point of delivery. To qualify for service under this Rider, Customer must meet the qualifications under A. or B. below:

A. Customer employ an additional workforce in Company's service area of a minimum of seventy-five (75) full time equivalent (FTE) employees. Employment additions must occur following Company's approval for service under this Rider.

B. Customer's New Load must result in capital investment of four hundred thousand dollars ($400,000), provided that such investment is accompanied by a net increase in full time equivalent employees employed by Customer in Company's service area. The capital investment must occur following Company's approval for service under this Rider.

This Rider is not available to a new customer which results from a change in ownership of an existing establishment. However, if a change in ownership occurs after Customer contracts for service under this Rider, the successor Customer may be allowed to fulfill the balance of the contract under Rider ED and continue the schedule of credits outlined below. This Rider is also not available for resumption of service following interruptions such as equipment failure, temporary plant shutdown, strike, or economic conditions. This Rider is also not available for: (1) load shifted from one establishment or delivery on Company's system to another on Company's system; (2) short-term, construction, or temporary service; (3) electrical load that results from the shutdown or reduction of generation facilities; or (4) service in conjunction with Transition Rider TR-1.

DEFINITIONS

New Load

New Load is that which is added to Company's system by a new establishment. For existing establishments, New Load is the net incremental load above that which existed prior to approval for service under this Rider. The New Load shall exclude any curtailable, back-up, standby, dispatched power, or incremental power service.

Delivery Date

The Delivery Date is the first date service is supplied under the contract.

Operational Date

The Operational Date shall be the date the facility is fully operational as declared by the Customer, but shall be no more than eighteen (18) months after the Delivery Date.

Month

The term "month" as used in this Rider means the period intervening between readings for the purpose of monthly billings. Readings will be collected each month at intervals of approximately thirty (30) days.

GENERAL PROVISIONS

1. Customer must make an application to Company for service under this Rider and Company must approve such application before Customer may receive service hereunder. The application must include a description of the amount of and nature of the New Load and the basis on which Customer requests qualification shown in A. or B. under Availability above. In the application, Customer must affirm that availability of this Rider was a factor in Customer's decision to locate the New Load on Company's system. The application shall also specify the total number of full time equivalent employees (FTE) employed by Customer in all establishments receiving electric service from Company's system, at the time of application for this Rider, and on the Operational Date.

2. Customer must agree to a minimum contract term of five (5) years, with the credits being available for a maximum period of five (5) years immediately following the Operational Date.

3. For customers contracting under this Rider due to expansion, Company may install metering equipment necessary to measure the New Load to be billed under this Rider separate from the existing load billed under the applicable rate schedule. Company reserves the right to make the determination of whether such installation will be separately metered or submetered. If in Company's opinion, the nature of the expansion is such that either separate metering or submetering is impractical or economically infeasible, Company will determine, based on historical usage, what portion of Customer's load, if any, qualifies as New Load eligible for this Rider.

4. All terms and conditions of the Large General Service and Large General Service (Time-of-Use) Schedules applicable to the individual customer shall apply to the service supplied to Customer, except as modified by this Rider.

MONTHLY BILLING

The Monthly Billing shall be the amount computed under the applicable schedule and other riders with which this Rider is used less the following Discount as computed in the formula below:

$$\text{Discount} = \text{New Load kW} \times \text{EDC}$$

Where:

New Load kW = the maximum 15-minute kW demand registered or computed (during on-peak hours when used in conjunction with the Large General Service (Time-of-Use) Schedule) associated with New Load added by Customer in accordance with this Rider.

EDC = the Economic Development Credit per kW as specified in the table below based on monthly load factor and the number of months service has been rendered under this Rider.

ECONOMIC DEVELOPMENT CREDIT (EDC)

Number of Months Service Has Been Rendered Under This Rider

LOAD FACTOR*	1 - 12	13 - 24	25 - 36	37 - 48	49 - 60
40% - 59%	$3.50	$2.80	$2.10	$1.40	$0.70
60% - 79%	$5.50	$4.40	$3.30	$2.20	$1.10
80% or greater	$7.50	$6.00	$4.50	$3.00	$1.50

* Load Factor is equal to the kilowatt-hours (kWh) used during the billing month divided by the product of the maximum 15-minute kW demand registered or computed times 730 hours.

The Discount shall be zero ($0) for load factors less than 40% or for service after sixty (60) monthly bills under this Rider.

ADDITIONAL FACILITIES CHARGE

A monthly facilities charge equal to 2.0% of the installed cost of extra facilities necessary for service for additional metering required under Rider ED, but not less than $25, shall be billed to Customer in addition to the bill under the appropriate rate schedule and this Rider, when applicable.

CONTRACT PERIOD

Each customer shall enter into a Service Agreement to purchase electricity from Company for a minimum original term of five (5) years, and thereafter from year to year upon the condition that either party can terminate the Service Agreement at the end of the original term, or at any time thereafter, by giving at least twelve (12) months previous notice of such termination in writing. If Customer requests a change in rate schedule from that which was approved in conjunction with Rider ED, credit under Rider ED will no longer be available. Such a change will be allowed upon thirty (30) days written notice to Company. An individual establishment will not be allowed to receive credits for more than five years under this Rider, unless Company, at its option, agrees to accept a new application and contract for qualifying New Load, and such application receives special approval by Company. If at any time during the term of contract under this Rider, Customer violates any of the terms and conditions of the Rider or the Service Agreement, Company may discontinue service under this Rider without notice and bill Customer under the applicable schedule without further credits. In the event electric service is terminated or the Contract Demand is reduced by Company or Customer before the end of the Contract Period, Customer shall pay Company in addition to all other applicable charges, the sum of all Discounts received, plus interest, for the New Load that will no longer be served by Company. The rate of interest shall be the rate per annum paid by Company for electric service deposits pursuant to Commission Rule R12-4.

GENERAL

Kilowatt demands associated with dispatched power, incremental power, back-up, or standby service shall be disregarded from all applications of this Rider, except for the calculation of Load Factor as defined in the Monthly Billing provision.

The provisions of the Schedule with which this Rider is used are modified only as shown herein.

Supersedes Rider ED-7
Effective for service rendered on and after December 14, 2006
NCUC Docket No. E-2, Sub 681