Financial Impact Estimating Conference (FIEC)

Notebook

Rights of Electricity Consumers Regarding Solar Energy Choice

15-17

Financial Impact Estimating Conference

Rights of Electricity Consumers Regarding Solar Energy Choice

Serial Number 15-17

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Authorization

FLORIDA DEPARTMENT of STATE

RICK SCOTT
Governor

KEN DETZNER
Secretary of State

October 19, 2015

Financial Impact Estimating Conference
c/o Ms. Amy Baker, Coordinator
Office of Economic and Demographic Research
111 West Madson Street, Ste. 574
Tallahassee, Florida 32399-6588

RECEIVED 10/26/15 9:30am SVB

Dear Ms. Baker:

Section 15.21, Florida Statutes, provides that the Secretary of State shall submit an initiative petition to the Financial Impact Estimating Conference when a sponsoring political committee has met the registration, petition form submission and signature criteria set forth in that section.

The criteria in section 15.21, Florida Statutes, has now been met for the initiative petition titled *Rights of Electricity Consumers Regarding Solar Energy Choice*, Serial Number 15-17. Therefore, I am submitting the proposed constitutional amendment petition form, along with a status update for the initiative petition, and a chart that provides a statewide signature count and count by congressional districts.

Sincerely,

Ken Detzner
Secretary of State

KD/am

pc: Jim Kallinger, Chairperson
Consumers for Smart Solar

Enclosures

CONSTITUTIONAL AMENDMENT PETITION FORM

Note:
- *All information on this form, including your signature, becomes a public record upon receipt by the Supervisor of Elections.*
- *Under Florida law, it is a first degree misdemeanor, punishable as provided in s. 775.082 or s. 775.08, Florida Statutes, to knowingly sign more than one petition for an issue. [Section 104.185, Florida Statutes]*
- *If all requested information on this form is not completed, the form will not be valid.*

Your name: ______________________________

Please Print Name ***as it appears on your Voter Information Card***

Your address: ______________________________

City ______________ **Zip** ________ **County** ______________

☐ Please change my legal residence address on my voter registration record to the above residence address (check box, if applicable).

Voter Registration Number ______________ **or Date of Birth** ______________

I am a registered voter of Florida and hereby petition the Secretary of State to place the following proposed amendment to the Florida Constitution on the ballot in the general election:

BALLOT TITLE: Rights of Electricity Consumers Regarding Solar Energy Choice

BALLOT SUMMARY: This amendment establishes a right under Florida's constitution for consumers to own or lease solar equipment installed on their property to generate electricity for their own use. State and local governments shall retain their abilities to protect consumer rights and public health, safety and welfare, and to ensure that consumers who do not choose to install solar are not required to subsidize the costs of backup power and electric grid access to those who do.

ARTICLE AND SECTION BEING CREATED OR AMENDED: Add new Section 29 to Article X

FULL TEXT OF THE PROPOSED CONSTITUTIONAL AMENDMENT:

Section 29 – Rights of electricity consumers regarding solar energy choice. –

(a) ESTABLISHMENT OF CONSTITUTIONAL RIGHT. Electricity consumers have the right to own or lease solar equipment installed on their property to generate electricity for their own use.

(b) RETENTION OF STATE AND LOCAL GOVERNMENTAL ABILITIES. State and local governments shall retain their abilities to protect consumer rights and public health, safety and welfare, and to ensure that consumers who do not choose to install solar are not required to subsidize the costs of backup power and electric grid access to those who do.

(c) DEFINITIONS. For purposes of this section, the following words and terms shall have the following meanings:

(1) "consumer" means any end user of electricity regardless of the source of that electricity.

(2) "solar equipment," "solar electrical generating equipment" and "solar" are used interchangeably and mean photovoltaic panels and any other device or system that converts sunlight into electricity.

(3) "backup power" means electricity from an electric utility, made available to solar electricity consumers for their use when their solar electricity generation is insufficient or unavailable, such as at night, during periods of low solar electricity generation or when their solar equipment otherwise is not functioning.

(4) "lease," when used in the context of a consumer paying the owner of solar electrical generating equipment for the right to use such equipment, means an agreement under which the consumer pays the equipment owner/lessor a stream of periodic payments for the use of such equipment, which payments do not vary in amount based on the amount of electricity produced by the equipment and used by the consumer/lessee.

(5) "electric grid" means the interconnected electrical network, consisting of power plants and other generating facilities, transformers, transmission lines, distribution lines and related facilities, that makes electricity available to consumers throughout Florida.

(6) "electric utility" means any municipal electric utility, investor-owned electric utility, or rural electric cooperative which owns, maintains, or operates an electric generation, transmission, or distribution system within the state.

(d) EFFECTIVE DATE. This section shall be effective immediately upon voter approval of this amendment.

______________________ X ______________________

DATE OF SIGNATURE **SIGNATURE OF REGISTERED VOTER**

Initiative petition sponsored by Consumers for Smart Solar, 2640-A Mitcham Drive, Tallahassee, FL 32308

If paid petition circulator is used:

Circulator's name ______________________

Circulator's address ______________________

____

For Official Use Only:

Serial Number: 15-17

Date Approved: 7/21/2015

Attachment for Initiative Petition
Rights of Electricity Consumers Regarding Solar Energy Choice
Serial Number 15-17

1. **Name and address of the sponsor of the initiative petition:**
   Jim Kallinger, Chairperson
   Consumers for Smart Solar
   2640-A Mitcham Drive
   Tallahassee, FL 32308-0000

2. **Name and address of the sponsor's attorney, if the sponsor is represented:**
   Unknown

3. **A statement as to whether the sponsor has obtained the requisite number of signatures on the initiative petition to have the proposed amendment put on the ballot:** As of October 19, 2015, the sponsor has not obtained the requisite number of signatures to have the proposed amendment placed on the ballot. A total of 683,149 valid signatures are required for placement on the 2016 general election ballot.

4. **If the sponsor has not obtained the requisite number of signatures on the initiative petition to have the proposed amendment put on the ballot, the current status of the signature-collection process:** As of October 19, 2015, the Supervisors of Elections have certified a total of 68,792 valid petition signatures to the Division of Elections for this initiative petition. This number represents more than 10% of the total number of valid signatures needed from electors statewide and in at least one-fourth of the congressional districts in order to have the initiative placed on the 2016 general election ballot.

5. **The date of the election during which the sponsor is planning to submit the proposed amendment to the voters:** Unknown. The earliest date of election that this proposed amendment can be placed on the ballot is November 8, 2016, provided the sponsor successfully obtains the requisite number of valid signatures by February 1, 2016.

6. **The last possible date that the ballot for the target election can be printed in order to be ready for the election:** Unknown

7. **A statement identifying the date by which the Financial Impact Statement will be filed, if the Financial Impact Statement is not filed concurrently with the request:** The Secretary of State forwarded a letter to the Financial Impact Estimating Conference in the care of the coordinator on October 19, 2015.

8. **The names and complete mailing addresses of all of the parties who are to be served:** This information is unknown at this time.

FLORIDA DEPARTMENT OF STATE
DIVISION OF ELECTIONS

SUMMARY OF PETITION SIGNATURES

Political Committee: **Consumers for Smart Solar**

Amendment Title: **Rights of Electricity Consumers Regarding Solar Energy Choice**

Congressional District	Voting Electors in 2012 Presidential Election	For Review 10% of 8% Required By Section 15.21 Florida Statutes	For Ballot 8% Required By Article XI, Section 3 Florida Constitution	Signatures Certified	
FIRST	356,435	2,851	28,515	0	
SECOND	343,558	2,748	27,485	585	
THIRD	329,165	2,633	26,333	1,085	
FOURTH	351,564	2,813	28,125	928	
FIFTH	279,598	2,237	22,368	4,651	***
SIXTH	363,402	2,907	29,072	3,245	***
SEVENTH	333,990	2,672	26,719	3,544	***
EIGHTH	365,738	2,926	29,259	1,130	
NINTH	277,101	2,217	22,168	4,872	***
TENTH	329,366	2,635	26,349	3,125	***
ELEVENTH	359,004	2,872	28,720	3,485	***
TWELFTH	345,407	2,763	27,633	2,506	
THIRTEENTH	344,500	2,756	27,560	3,226	***
FOURTEENTH	295,917	2,367	23,673	3,290	***
FIFTEENTH	304,932	2,439	24,395	1,567	
SIXTEENTH	360,734	2,886	28,859	783	
SEVENTEENTH	299,464	2,396	23,957	2,838	***
EIGHTEENTH	345,399	2,763	27,632	548	
NINETEENTH	323,317	2,587	25,865	1,693	
TWENTIETH	264,721	2,118	21,178	3,568	***
TWENTY-FIRST	326,392	2,611	26,111	1,265	
TWENTY-SECOND	329,816	2,639	26,385	2,180	
TWENTY-THIRD	290,042	2,320	23,203	4,192	***
TWENTY-FOURTH	263,367	2,107	21,069	8,082	***
TWENTY-FIFTH	240,521	1,924	19,242	1,451	
TWENTY-SIXTH	268,898	2,151	21,512	2,525	***
TWENTY-SEVENTH	247,023	1,976	19,762	2,428	***
TOTAL:	**8,539,371**	**68,314**	**683,149**	**68,792**	

*** Initiative has met the 10% of 8% threshold in congressional district

Date: 10/15/2015 2:18:15 PM

Select Year: 2014 Go

The 2014 Florida Statutes

100.371 Initiatives; procedure for placement on ballot.—

(1) Constitutional amendments proposed by initiative shall be placed on the ballot for the general election, provided the initiative petition has been filed with the Secretary of State no later than February 1 of the year the general election is held. A petition shall be deemed to be filed with the Secretary of State upon the date the secretary determines that valid and verified petition forms have been signed by the constitutionally required number and distribution of electors under this code.

(2) The sponsor of an initiative amendment shall, prior to obtaining any signatures, register as a political committee pursuant to s. 106.03 and submit the text of the proposed amendment to the Secretary of State, with the form on which the signatures will be affixed, and shall obtain the approval of the Secretary of State of such form. The Secretary of State shall adopt rules pursuant to s. 120.54 prescribing the style and requirements of such form. Upon filing with the Secretary of State, the text of the proposed amendment and all forms filed in connection with this section must, upon request, be made available in alternative formats.

(3) An initiative petition form circulated for signature may not be bundled with or attached to any other petition. Each signature shall be dated when made and shall be valid for a period of 2 years following such date, provided all other requirements of law are met. The sponsor shall submit signed and dated forms to the supervisor of elections for the county of residence listed by the person signing the form for verification of the number of valid signatures obtained. If a signature on a petition is from a registered voter in another county, the supervisor shall notify the petition sponsor of the misfiled petition. The supervisor shall promptly verify the signatures within 30 days after receipt of the petition forms and payment of the fee required by s. 99.097. The supervisor shall promptly record, in the manner prescribed by the Secretary of State, the date each form is received by the supervisor, and the date the signature on the form is verified as valid. The supervisor may verify that the signature on a form is valid only if:

(a) The form contains the original signature of the purported elector.

(b) The purported elector has accurately recorded on the form the date on which he or she signed the form.

(c) The form sets forth the purported elector's name, address, city, county, and voter registration number or date of birth.

(d) The purported elector is, at the time he or she signs the form and at the time the form is verified, a duly qualified and registered elector in the state.

The supervisor shall retain the signature forms for at least 1 year following the election in which the issue appeared on the ballot or until the Division of Elections notifies the supervisors of elections that the committee that circulated the petition is no longer seeking to obtain ballot position.

(4) The Secretary of State shall determine from the signatures verified by the supervisors of elections the total number of verified valid signatures and the distribution of such signatures by congressional districts. Upon a determination that the requisite number and distribution of valid signatures have been obtained, the secretary shall issue a certificate of ballot position for that proposed amendment and shall assign a designating number pursuant to s. 101.161.

(5)(a) Within 45 days after receipt of a proposed revision or amendment to the State Constitution by initiative petition from the Secretary of State, the Financial Impact Estimating Conference shall complete an analysis and financial impact statement to be placed on the ballot of the estimated increase or decrease in any revenues or costs to state or local governments resulting from the proposed initiative. The Financial Impact Estimating Conference shall submit the financial impact statement to the Attorney General and Secretary of State.

(b) The Financial Impact Estimating Conference shall provide an opportunity for any proponents or opponents of the initiative to submit information and may solicit information or analysis from any other entities or agencies, including the Office of Economic and Demographic Research.

(c) All meetings of the Financial Impact Estimating Conference shall be open to the public. The President of the Senate and the Speaker of the House of Representatives, jointly, shall be the sole judge for the interpretation, implementation, and enforcement of this subsection.

1. The Financial Impact Estimating Conference is established to review, analyze, and estimate the financial impact of amendments to or revisions of the State Constitution proposed by initiative. The Financial Impact Estimating Conference shall consist of four principals: one person from the Executive Office of the Governor; the coordinator of the Office of Economic and Demographic Research, or his or her designee; one person from the professional staff of the Senate; and one person from the professional staff of the House of Representatives. Each principal shall have appropriate fiscal expertise in the subject matter of the initiative. A Financial Impact Estimating Conference may be appointed for each initiative.

2. Principals of the Financial Impact Estimating Conference shall reach a consensus or majority concurrence on a clear and unambiguous financial impact statement, no more than 75 words in length, and immediately submit the statement to the Attorney General. Nothing in this subsection prohibits the Financial Impact Estimating Conference from setting forth a range of potential impacts in the financial impact statement. Any financial impact statement that a court finds not to be in accordance with this section shall be remanded solely to the Financial Impact Estimating Conference for redrafting. The Financial Impact Estimating Conference shall redraft the financial impact statement within 15 days.

3. If the members of the Financial Impact Estimating Conference are unable to agree on the statement required by this subsection, or if the Supreme Court has rejected the initial submission by the Financial Impact Estimating Conference and no redraft has been approved by the Supreme Court by 5 p.m. on the 75th day before the election, the following statement shall appear on the ballot pursuant to s. 101.161(1): "The financial impact of this measure, if any, cannot be reasonably determined at this time."

(d) The financial impact statement must be separately contained and be set forth after the ballot summary as required in s. 101.161(1).

(e)1. Any financial impact statement that the Supreme Court finds not to be in accordance with this subsection shall be remanded solely to the Financial Impact Estimating Conference for redrafting, provided the court's advisory opinion is rendered at least 75 days before the election at which the question of ratifying the amendment will be presented. The Financial Impact Estimating Conference shall prepare and adopt a revised financial impact statement no later than 5 p.m. on the 15th day after the date of the court's opinion.

2. If, by 5 p.m. on the 75th day before the election, the Supreme Court has not issued an advisory opinion on the initial financial impact statement prepared by the Financial Impact Estimating Conference for an initiative amendment that otherwise meets the legal requirements for ballot placement, the financial impact statement shall be deemed approved for placement on the ballot.

3. In addition to the financial impact statement required by this subsection, the Financial Impact Estimating Conference shall draft an initiative financial information statement. The initiative financial information statement should describe in greater detail than the financial impact statement any projected increase or decrease in revenues or costs that the state or local governments would likely experience if the ballot measure were approved. If appropriate, the initiative financial information statement may include both estimated dollar amounts and a description placing the estimated dollar amounts into context. The initiative financial information statement must include both a summary of not more than 500 words and additional detailed information that includes the assumptions that were made to develop the financial impacts, workpapers, and any other information deemed relevant by the Financial Impact Estimating Conference.

4. The Department of State shall have printed, and shall furnish to each supervisor of elections, a copy of the summary from the initiative financial information statements. The supervisors shall have the summary from the initiative financial information statements available at each polling place and at the main office of the supervisor of elections upon request.

5. The Secretary of State and the Office of Economic and Demographic Research shall make available on the Internet each initiative financial information statement in its entirety. In addition, each supervisor of elections whose office has a website shall post the summary from each initiative financial information statement on the website. Each supervisor shall include the Internet addresses for the information statements on the Secretary of State's and the Office of Economic and Demographic Research's websites in the publication or mailing required by s. 101.20.

(6) The Department of State may adopt rules in accordance with s. 120.54 to carry out the provisions of subsections (1)-(5).

(7) No provision of this code shall be deemed to prohibit a private person exercising lawful control over privately owned property, including property held open to the public for the purposes of a commercial enterprise, from excluding from such property persons seeking to engage in activity supporting or opposing initiative amendments.

History.—s. 15, ch. 79-365; s. 12, ch. 83-251; s. 30, ch. 84-302; s. 22, ch. 97-13; s. 9, ch. 2002-281; s. 3, ch. 2002-390; s. 3, ch. 2004-33; s. 28, ch. 2005-278; s. 4, ch. 2006-119; s. 25, ch. 2007-30; s. 1, ch. 2007-231; s. 14, ch. 2008-95; s. 23, ch. 2011-40.

Tab 2

Current Law

Tab 2 – Current Law

<u>Statutes</u>

ch. 203, F.S. – Gross Receipts Tax

s. 366.02, F.S. – Public Utilities Definitions

s. 212.05, F.S. – Sales Tax on Electricity

s. 212.08 (7)(j), F.S. – Sales Tax Exemption for Household Fuels

s. 212.08(7)(hh), F.S. – Sales Tax Exemption for Solar Energy Systems

s. 193.624, F.S. – Assessment of Residential Property

s. 163.04, F.S. – Energy Devices Based on Renewable Resources

s. 163.08, F.S. – Supplemental Authority for Improvements to Real Property

s. 366.91, F.S. – Renewable Energy

s. 377.705, F.S. – Solar Energy Center; Development of Solar Energy Standards

s. 403.503, F.S. – Definitions Relating to Florida Electrical Power Siting Act

s.166.231, F.S. – Municipalities; Public Service Tax

s. 366.14, F.S. – Regulatory Assessment Fees

<u>Rules</u>

25-6.065 – Interconnection and Net Metering of Customer-Owned Renewable Generation

25-6.0131 – Regulatory Assessment Fees; Investor-owned Electric Companies, Municipal Electric Utilities, Rural Electric Cooperatives.

The Florida Senate

2014 Florida Statutes

Title XIV	Chapter 203
TAXATION AND FINANCE	GROSS RECEIPTS TAXES

CHAPTER 203
GROSS RECEIPTS TAXES

[1]**203.001 Combined rate for tax collected pursuant to ss. 202.12(1)(a) and 203.01(1)(b).**—In complying with ss. 1-3, ch. 2010-149, Laws of Florida, the dealer of communication services may collect a combined rate of 6.8 percent comprised of 6.65 percent and 0.15 percent required by ss. 202.12(1)(a) and 203.01(1)(b)3., respectively, as long as the provider properly reflects the tax collected with respect to the two provisions as required in the return to the Department of Revenue.

History.—s. 5, ch. 2010-149.

[1]**Note.**—

A. Also published at s. 202.12001.

B. Section 6, ch. 2010-149, provides that "[t]he Department of Revenue may, and all conditions are deemed met to, adopt emergency rules pursuant to ss. 120.536(1) and 120.54, Florida Statutes, for the purpose of promulgating such forms and instructions as are required to effectuate this act."

[1]**203.0011 Combined rate for tax collected pursuant to ss. 203.01(1)(b)4. and 212.05(1)(e)1.c.**—In complying with the amendments to ss. 203.01 and 212.05, relating to the additional tax on electrical power or energy, made by this act, a seller of electrical power or energy may collect a combined rate of 6.95 percent, which consists of the 4.35 percent and 2.6 percent required under ss. 212.05(1)(e)1.c. and 203.01(1)(b)4., respectively, if the provider properly reflects the tax collected with respect to the two provisions as required in the return to the Department of Revenue.

History.—s. 6, ch. 2014-38.

[1]**Note.**—Also published at s. 212.05011.

203.01 Tax on gross receipts for utility and communications services.—

[1](1)(a)1. A tax is imposed on gross receipts from utility services that are delivered to a retail consumer in this state. The tax shall be levied as provided in paragraphs (b)-(j).

2. A tax is levied on communications services as defined in s. 202.11(1). The tax shall be applied to the same services and transactions as are subject to taxation under chapter 202, and to communications services that are subject to the exemption provided in s. 202.125(1). The tax shall be applied to the sales price of communications services when

sold at retail, as the terms are defined in s. 202.11, shall be due and payable at the same time as the taxes imposed pursuant to chapter 202, and shall be administered and collected pursuant to chapter 202.

3. An additional tax is levied on charges for, or the use of, electrical power or energy that is subject to the tax levied pursuant to s. 212.05(1)(e)1.c. or s. 212.06(1). The tax shall be applied to the same transactions or uses as are subject to taxation under s. 212.05(1)(e)1.c. or s. 212.06(1). If a transaction or use is exempt from the tax imposed under s. 212.05(1)(e)1.c. or s. 212.06(1), the transaction or use is also exempt from the tax imposed under this subparagraph. The tax shall be applied to charges for electrical power or energy and is due and payable at the same time as taxes imposed pursuant to chapter 212. Chapter 212 governs the administration and enforcement of the tax imposed by this subparagraph. The charges upon which the tax imposed by this subparagraph is applied do not include the taxes imposed by subparagraph 1. or s. 166.231. The tax imposed by this subparagraph becomes state funds at the moment of collection and is not considered as revenue of a utility for purposes of a franchise agreement between the utility and a local government.

[2](b)1. The rate applied to utility services shall be 2.5 percent.

2. The rate applied to communications services shall be 2.37 percent.

3. An additional rate of 0.15 percent shall be applied to communication services subject to the tax levied pursuant to s. 202.12(1)(a), (c), and (d). The exemption provided in s. 202.125(1) applies to the tax levied pursuant to this subparagraph.

4. The rate applied to electrical power or energy taxed under subparagraph (a)3. shall be 2.6 percent.

(c)1. The tax imposed under subparagraph (a)1. shall be levied against the total amount of gross receipts received by a distribution company for its sale of utility services if the utility service is delivered to the retail consumer by a distribution company and the retail consumer pays the distribution company a charge for utility service which includes a charge for both the electricity and the transportation of electricity to the retail consumer. The distribution company shall report and remit to the Department of Revenue by the 20th day of each month the taxes levied pursuant to this paragraph during the preceding month.

2. To the extent practicable, the Department of Revenue must distribute all receipts of taxes remitted under this chapter to the Public Education Capital Outlay and Debt Service Trust Fund in the same month as the department collects such taxes.

(d)1. Each distribution company that receives payment for the delivery of electricity to a retail consumer in this state is subject to tax on the exercise of this privilege as provided by this paragraph unless the payment is subject to tax under paragraph (c). For the exercise of this privilege, the tax levied on the distribution company's receipts for the delivery of electricity shall be determined by multiplying the number of kilowatt hours delivered by the index price and applying the rate in subparagraph (b)1. to the result.

2. The index price is the Florida price per kilowatt hour for retail consumers in the previous calendar year, as published in the United States Energy Information Administration Electric Power Monthly and announced by the Department of Revenue on June 1 of each year to be effective for the 12-month period beginning July 1 of that year. For each residential, commercial, and industrial customer class, the applicable index posted for residential, commercial, and industrial shall be applied in calculating the gross receipts to which the tax applies. If publication of the indices is delayed or discontinued, the last posted index shall be used until a current index is posted or the department adopts a comparable index by rule.

3. Tax due under this paragraph shall be administered, paid, and reported in the same manner as the tax due under paragraph (c).

4. The amount of tax due under this paragraph shall be reduced by the amount of any like tax lawfully imposed on and paid by the person from whom the retail consumer purchased the electricity, whether imposed by and paid to this state, another state, a territory of the United States, or the District of Columbia. This reduction in tax shall be available to the retail consumer as a refund made pursuant to s. 215.26 and does not inure to the benefit of the person who receives payment for the delivery of the electricity. The methods of demonstrating proof of payment and the amount of such refund shall be made according to rules of the Department of Revenue.

(e)1. A distribution company that receives payment for the sale or transportation of natural or manufactured gas to a retail consumer in this state is subject to tax on the exercise of this privilege as provided by this paragraph. For the exercise of this privilege, the tax levied on the distribution company's receipts for the sale or transportation of natural or manufactured gas shall be determined by dividing the number of cubic feet delivered by 1,000, multiplying the resulting number by the index price, and applying the rate in subparagraph (b)1. to the result.

2. The index price is the Florida price per 1,000 cubic feet for retail consumers in the previous calendar year as published in the United States Energy Information Administration Natural Gas Monthly and announced by the Department of Revenue on June 1 of each year to be effective for the 12-month period beginning July 1 of that year. For each residential, commercial, and industrial customer class, the applicable index posted for residential, commercial, and industrial shall be applied in calculating the gross receipts to which the tax applies. If publication of the indices is delayed or discontinued, the last posted index shall be used until a current index is posted or the department adopts a comparable index by rule.

3. Tax due under this paragraph shall be administered, paid, and reported in the same manner as the tax due under paragraph (c).

4. The amount of tax due under this paragraph shall be reduced by the amount of any like tax lawfully imposed on and paid by the person from whom the retail consumer purchased the natural gas or manufactured gas, whether imposed by and paid to this state, another state, a territory of the United States, or the District of Columbia. This reduction in tax shall be available to the retail consumer as a refund pursuant to s. 215.26 and does not inure to the benefit of the person providing the transportation service. The methods of demonstrating proof of payment and the amount of such refund shall be made according to rules of the Department of Revenue.

(f) Any person who imports into this state electricity, natural gas, or manufactured gas, or severs natural gas, for that person's own use or consumption as a substitute for purchasing utility, transportation, or delivery services taxable under subparagraph (a)1. and who cannot demonstrate payment of the tax imposed by this chapter must register with the Department of Revenue and pay into the State Treasury each month an amount equal to the cost price, as defined in s. 212.02, of such electricity, natural gas, or manufactured gas times the rate set forth in subparagraph (b)1., reduced by the amount of any like tax lawfully imposed on and paid by the person from whom the electricity, natural gas, or manufactured gas was purchased or any person who provided delivery service or transportation service in connection with the electricity, natural gas, or manufactured gas. The methods of demonstrating proof of payment and the amount of such reductions in tax shall be made according to rules of the Department of Revenue.

(g) Electricity produced by cogeneration or by small power producers which is transmitted and distributed by a public utility between two locations of a customer of the utility pursuant to s. 366.051 is subject to the tax imposed by subparagraph (a)1. The tax shall be applied to the cost price, as defined in s. 212.02, of such electricity and shall be paid each month by the producer of such electricity.

(h) Electricity produced by cogeneration or by small power producers during the 12-month period ending June 30 of each year which is in excess of nontaxable electricity produced during the 12-month period ending June 30, 1990, is subject to the tax imposed by subparagraph (a)1. The tax shall be applied to the cost price, as defined in s. 212.02, of such electricity and shall be paid each month, beginning with the month in which total production exceeds the production of nontaxable electricity for the 12-month period ending June 30, 1990. As used in this paragraph, the term "nontaxable electricity" means electricity produced by cogeneration or by small power producers which is not subject to tax under paragraph (g). Taxes paid pursuant to paragraph (g) may be credited against taxes due under this paragraph. Electricity generated as part of an industrial manufacturing process that manufactures products from phosphate rock, raw wood fiber, paper, citrus, or any agricultural product is not subject to the tax imposed by this paragraph. The term "industrial manufacturing process" means the entire process conducted at the location where the process takes place.

(i) Any person other than a cogenerator or small power producer described in paragraph (h) who produces for his or her own use electrical energy that is a substitute for electrical energy produced by an electric utility as defined in s.

366.02 is subject to the tax imposed by subparagraph (a)1. The tax shall be applied to the cost price, as defined in s. 212.02, of such electrical energy and shall be paid each month. This paragraph does not apply to electrical energy produced and used by an electric utility.

(j) Notwithstanding any other provision of this chapter, with the exception of a communications services dealer reporting taxes administered under chapter 202, the department may require:

1. A quarterly return and payment when the tax remitted for the preceding four calendar quarters did not exceed $1,000;

2. A semiannual return and payment when the tax remitted for the preceding four calendar quarters did not exceed $500; or

3. An annual return and payment when the tax remitted for the preceding four calendar quarters did not exceed $100.

(2)(a) In addition to any other penalty provided by law, any person who fails to timely report and pay any tax imposed on gross receipts from utility services under this chapter shall pay a penalty equal to 10 percent of any unpaid tax, if the failure is for less than 31 days, plus an additional 10 percent of any unpaid tax for each additional 30 days or fraction thereof. However, such penalty may not be less than $10 or exceed a total of 50 percent in the aggregate of any unpaid tax.

(b) In addition to any other penalty provided by law, any person who falsely or fraudulently reports or unlawfully attempts to evade paying any tax imposed on gross receipts from utility services under this chapter shall pay a penalty equal to 100 percent of any tax due and is guilty of a misdemeanor of the second degree, punishable as provided under s. 775.082 or s. 775.083.

[1](3) The tax imposed by subparagraph (1)(a)1. does not apply to:

(a)1. The sale or transportation of natural gas or manufactured gas to a public or private utility, including a municipal corporation or rural electric cooperative association, for resale or for use as fuel in the generation of electricity; or

2. The sale or delivery of electricity to a public or private utility, including a municipal corporation or rural electric cooperative association, for resale, or as part of an electrical interchange agreement or contract between such utilities for the purpose of transferring more economically generated power;

if the person deriving gross receipts from such sale demonstrates that a sale, transportation, or delivery for resale in fact occurred and complies with the following requirements: A sale, transportation, or delivery for resale must be in strict compliance with the rules of the Department of Revenue; and any sale subject to the tax imposed by this section which is not in strict compliance with the rules of the Department of Revenue shall be subject to the tax at the appropriate rate imposed on utilities under subparagraph (1)(b)1. on the person making the sale. Any person making a sale for resale may, through an informal protest provided in s. 213.21 and the rules of the Department of Revenue, provide the department with evidence of the exempt status of a sale. The department shall adopt rules that provide that valid proof and documentation of the resale by a person making the sale for resale will be accepted by the department when submitted during the protest period but will not be accepted when submitted in any proceeding under chapter 120 or any circuit court action instituted under chapter 72;

(b) Wholesale sales of electric transmission service;

(c) The use of natural gas in the production of oil or gas, or the use of natural or manufactured gas by a person transporting natural or manufactured gas, when used and consumed in providing such services; or

(d) The sale or transportation to, or use of, natural gas or manufactured gas by a person eligible for an exemption under s. 212.08(7)(ff)2. for use as an energy source or a raw material. Possession by a seller of natural or manufactured gas or by any person providing transportation or delivery of natural or manufactured gas of a written certification by the purchaser, certifying the purchaser’s entitlement to the exclusion permitted by this paragraph, relieves the seller or person providing transportation or delivery from the responsibility of remitting tax on the nontaxable amounts, and the department shall look solely to the purchaser for recovery of such tax if the department determines that the purchaser was not entitled to the exclusion. The certification must include an acknowledgment by the purchaser that it will be liable for tax pursuant to paragraph (1)(f) if the requirements for exclusion are not met.

[1](4) The tax imposed pursuant to subparagraph (1)(a)1. relating to the provision of utility services at the option of the person supplying the taxable services may be separately stated as Florida gross receipts tax on the total amount of any bill, invoice, or other tangible evidence of the provision of such taxable services and may be added as a component part of the total charge. If a provider of taxable services elects to separately state such tax as a component of the charge for the provision of such taxable services, any person, including all governmental units, shall remit the tax to the person who provides such taxable services as a part of the total bill, and the tax is a component part of the debt of the purchaser to the person who provides such taxable services until paid and, if unpaid, is recoverable at law in the same manner as any other part of the charge for such taxable services. For a utility, the decision to separately state any increase in the rate of tax imposed by this chapter which is effective after December 31, 1989, and the ability to recover the increased charge from the customer is not subject to regulatory approval.

(5) The tax is imposed upon every person for the privilege of conducting a utility or communications services business, and each provider of the taxable services remains fully and completely liable for the tax, even if the tax is separately stated as a line item or component of the total bill.

(6) Any person who provides such services and who fails, neglects, or refuses to remit the tax imposed in this chapter, either by himself or herself, or through agents or employees, is liable for the tax and is guilty of a misdemeanor of the first degree, punishable as provided in s. 775.082 or s. 775.083.

[1](7) Gross receipts subject to the tax imposed under subparagraph (1)(a)1. for the provision of electricity must include receipts from monthly customer charges or monthly customer facility charges.

(8) Notwithstanding the provisions of subsection (4) and s. 212.07(2), sums that were charged or billed as taxes under this section and chapter 212 and that were remitted to the state in full as taxes shall not be subject to refund by the state or by the utility or other person that remitted the sums, when the amount remitted was not in excess of the amount of tax imposed by chapter 212 and this section.

(9) Any person who engages in the transportation of natural or manufactured gas shall furnish annually to the Department of Revenue a list of customers to whom transportation services were provided in the prior year. This reporting requirement does not apply to distribution companies. Any person required to furnish such a list may elect to identify only those customers who take direct delivery without purchasing interconnection services from a distribution company. Such reports are subject to the confidentiality provisions of s. 213.053. Any person required to furnish a customer list may instead comply by maintaining a publicly accessible customer list on its Internet website. Such list shall be updated no less than annually.

History.—ss. 1, 2, ch. 15658, 1931; CGL 1936 Supp. 1279(108), (109); s. 7, ch. 22858, 1945; s. 1, ch. 57-819; s. 7, ch. 63-253; s. 5, ch. 65-371; s. 2, ch. 65-420; ss. 21, 35, ch. 69-106; s. 10, ch. 75-292; s. 3, ch. 80-381; s. 15, ch. 83-137; ss. 1, 4, ch. 84-342; s. 29, ch. 85-116; s. 2, ch. 85-174; s. 2, ch. 86-155; s. 68, ch. 87-6; s. 41, ch. 87-101; s. 43, ch. 87-224; s. 7, ch. 89-292; s. 12, ch. 89-356; s. 14, ch. 90-132; s. 11, ch. 91-112; s. 234, ch. 91-224; s. 8, ch. 92-320; s. 10, ch. 93-233; s. 1054, ch. 95-147; s. 2, ch. 95-403; s. 12, ch. 96-397; s. 6, ch. 97-233; s. 11, ch. 98-277; ss. 40, 41, 58, ch. 2000-260; s. 10, ch. 2000-355; ss. 25, 38, ch. 2001-140; s. 1, ch. 2003-17; s. 178, ch. 2003-261; s. 1, ch. 2005-148; s. 7, ch. 2005-187; s. 2, ch. 2007-60; s. 3, ch. 2010-149; s. 9, ch. 2012-70; s. 4, ch. 2014-38.

[1]**Note.**—

A. Section 5, ch. 2014-38, provides that "[t]he amendments to s. 212.05(1)(e)1.c. made in section 2 of this act and to s. 203.01 made in section 4 of this act apply to taxable transactions included on bills that are for utility services and that are dated on or after July 1, 2014."

B. Section 12, ch. 2014-38, provides that "[t]he Department of Revenue may, and all conditions are deemed met to, adopt emergency rules pursuant to ss. 120.536(1) and 120.54, Florida Statutes, for the purpose of implementing the amendments to ss. 203.01, 212.05, 212.12, and 212.20, Florida Statutes, relating to changes to the taxation of electrical power or energy, made by this act. This section expires July 1, 2017."

[2]**Note.**—Section 6, ch. 2010-149, provides that "[t]he Department of Revenue may, and all conditions are deemed met to, adopt emergency rules pursuant to ss. 120.536(1) and 120.54, Florida Statutes, for the purpose of promulgating such forms and instructions as are required to effectuate this act."

203.0111 Application of tax increase.—With respect to utility services regularly billed on a monthly cycle basis, each increase in the gross receipts tax provided for in this act shall apply to any bill dated on or after July 1 in the year in which the increase becomes effective.

History.—s. 16, ch. 90-132.

203.012 Definitions.—As used in this chapter:

(1) "Distribution company" means any person owning or operating local electric or natural or manufactured gas utility distribution facilities within this state for the transmission, delivery, and sale of electricity or natural or manufactured gas. The term does not include natural gas transmission companies that are subject to the jurisdiction of the Federal Energy Regulatory Commission.

(2) "Person" means any person as defined in s. 212.02.

(3) "Utility service" means electricity for light, heat, or power; and natural or manufactured gas for light, heat, or power, including transportation, delivery, transmission, and distribution of the electricity or natural or manufactured gas. This subsection does not broaden the definition of utility service to include separately stated charges for tangible personal property or services which are not charges for the electricity or natural or manufactured gas or the transportation, delivery, transmission, or distribution of electricity or natural or manufactured gas.

History.—ss. 2, 6, ch. 84-342; s. 30, ch. 85-116; s. 3, ch. 85-174; s. 3, ch. 86-155; s. 44, ch. 87-224; s. 17, ch. 90-132; s. 13, ch. 91-112; s. 1, ch. 97-283; ss. 42, 58, ch. 2000-260; s. 38, ch. 2001-140; s. 2, ch. 2005-148.

203.02 Powers of Department of Revenue.—The Department of Revenue may audit the reports provided for in s. 203.01; and each and every such person shall submit all records, books, papers and accounts as to business done to the department or its duly authorized agents for examination or investigation upon demand.

History.—s. 3, ch. 15658, 1931; CGL 1936 Supp. 1279(110); s. 7, ch. 63-253; s. 5, ch. 65-371; s. 2, ch. 65-420; ss. 21, 35, ch. 69-106.

203.03 Penalties.—

(1) Any officer, agent, or representative of any such person who receives any payment for the furnishing of the things or the services above mentioned without first complying with the provisions of this chapter is guilty of a misdemeanor of the first degree, punishable as provided in s. 775.082 or s. 775.083.

(2) Any person who willfully violates or fails to comply with any of the provisions of this chapter is guilty of a misdemeanor of the first degree, punishable as provided in s. 775.082 or s. 775.083.

History.—s. 4, ch. 15658, 1931; CGL 1936 Supp. 7455(3); s. 108, ch. 71-136; s. 69, ch. 87-6; s. 42, ch. 87-101; s. 15, ch. 91-224.

203.04 Construction of laws granting exemptions or exceptions.—No statute or law, general, special, or local hereafter enacted which either directly or indirectly relates to exemptions or exceptions from taxation in this state shall be construed as including or extending to the gross receipts taxes imposed by this chapter unless its application to said chapter, either directly or indirectly, is clearly and specifically expressed and no repeals by implication shall be recognized in this connection. This is a rule of statutory construction to be applied to statutes and laws hereafter enacted.

History.—ss. 1, 2, 3, ch. 63-535; s. 49, ch. 91-45; s. 13, ch. 96-397.

203.06 Interest on delinquent payments.—Any payments as imposed in this chapter, if not received by the Department of Revenue on or before the due date as provided by law, shall include, as an additional part of such amount due, interest at the rate of 1 percent per month, accruing from the date due until paid.

History.—s. 5, ch. 76-261.

203.07 Settlement or compromise of penalties and interest.—The department, pursuant to s. 213.21, may settle or compromise penalties or interest imposed by this chapter.

History.—s. 6, ch. 81-178.

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Title XXVII RAILROADS AND OTHER REGULATED UTILITIES	Chapter 366 PUBLIC UTILITIES Entire Chapter	**SECTION 02** **Definitions.**

366.02 Definitions.— As used in this chapter:

(1) "Public utility" means every person, corporation, partnership, association, or other legal entity and their lessees, trustees, or receivers supplying electricity or gas (natural, manufactured, or similar gaseous substance) to or for the public within this state; but the term "public utility" does not include either a cooperative now or hereafter organized and existing under the Rural Electric Cooperative Law of the state; a municipality or any agency thereof; any dependent or independent special natural gas district; any natural gas transmission pipeline company making only sales or transportation delivery of natural gas at wholesale and to direct industrial consumers; any entity selling or arranging for sales of natural gas which neither owns nor operates natural gas transmission or distribution facilities within the state; or a person supplying liquefied petroleum gas, in either liquid or gaseous form, irrespective of the method of distribution or delivery, or owning or operating facilities beyond the outlet of a meter through which natural gas is supplied for compression and delivery into motor vehicle fuel tanks or other transportation containers, unless such person also supplies electricity or manufactured or natural gas.

(2) "Electric utility" means any municipal electric utility, investor-owned electric utility, or rural electric cooperative which owns, maintains, or operates an electric generation, transmission, or distribution system within the state.

(3) "Commission" means the Florida Public Service Commission.

History.—s. 2, ch. 26545, 1951; s. 3, ch. 76-168; s. 1, ch. 77-457; ss. 2, 16, ch. 80-35; s. 2, ch. 81-318; ss. 1, 20, 22, ch. 89-292; s. 4, ch. 91-429; s. 14, ch. 92-284.

212.05 Sales, storage, use tax.—It is hereby declared to be the legislative intent that every person is exercising a taxable privilege who engages in the business of selling tangible personal property at retail in this state, including the business of making mail order sales, or who rents or furnishes any of the things or services taxable under this chapter, or who stores for use or consumption in this state any item or article of tangible personal property as defined herein and who leases or rents such property within the state.

(1) For the exercise of such privilege, a tax is levied on each taxable transaction or incident, which tax is due and payable as follows:

(e)1. At the rate of 6 percent on charges for:

c. Electrical power or energy, except that the tax rate for charges for electrical power or energy is 4.35 percent. Charges for electrical power and energy do not include taxes imposed under ss. 166.231 and 203.01(1)(a)3.

212.08 Sales, rental, use, consumption, distribution, and storage tax; specified exemptions.—The sale at retail, the rental, the use, the consumption, the distribution, and the storage to be used or consumed in this state of the following are hereby specifically exempt from the tax imposed by this chapter.

(7) MISCELLANEOUS EXEMPTIONS.—Exemptions provided to any entity by this chapter do not inure to any transaction that is otherwise taxable under this chapter when payment is made by a representative or employee of the entity by any means, including, but not limited to, cash, check, or credit card, even when that representative or employee is subsequently reimbursed by the entity. In addition, exemptions provided to any entity by this subsection do not inure to any transaction that is otherwise taxable under this chapter unless the entity has obtained a sales tax exemption certificate from the department or the entity obtains or provides other documentation as required by the department. Eligible purchases or leases made with such a certificate must be in strict compliance with this subsection and departmental rules, and any person who makes an exempt purchase with a certificate that is not in strict compliance with this subsection and the rules is liable for and shall pay the tax. The department may adopt rules to administer this subsection.

(j) Household fuels.—Also exempt from payment of the tax imposed by this chapter are sales of utilities to residential households or owners of residential models in this state by utility companies who pay the gross receipts tax imposed under s. 203.01, and sales of fuel to residential households or owners of residential models, including oil, kerosene, liquefied petroleum gas, coal, wood, and other fuel products used in the household or residential model for the purposes of heating, cooking, lighting, and refrigeration, regardless of whether such sales of utilities and fuels are separately metered and billed direct to the residents or are metered and billed to the landlord. If any part of the utility or fuel is used for a nonexempt purpose, the entire sale is taxable. The landlord shall provide a separate meter for nonexempt utility or fuel consumption. For the purposes of this paragraph, licensed family day care homes shall also be exempt.

212.08 Sales, rental, use, consumption, distribution, and storage tax; specified exemptions.—The sale at retail, the rental, the use, the consumption, the distribution, and the storage to be used or consumed in this state of the following are hereby specifically exempt from the tax imposed by this chapter.

(7) MISCELLANEOUS EXEMPTIONS.—Exemptions provided to any entity by this chapter do not inure to any transaction that is otherwise taxable under this chapter when payment is made by a representative or employee of the entity by any means, including, but not limited to, cash, check, or credit card, even when that representative or employee is subsequently reimbursed by the entity. In addition, exemptions provided to any entity by this subsection do not inure to any transaction that is otherwise taxable under this chapter unless the entity has obtained a sales tax exemption certificate from the department or the entity obtains or provides other documentation as required by the department. Eligible purchases or leases made with such a certificate must be in strict compliance with this subsection and departmental rules, and any person who makes an exempt purchase with a certificate that is not in strict compliance with this subsection and the rules is liable for and shall pay the tax. The department may adopt rules to administer this subsection.

(hh) *Solar energy systems.*—Also exempt are solar energy systems or any component thereof. The Florida Solar Energy Center shall from time to time certify to the department a list of equipment and requisite hardware considered to be a solar energy system or a component thereof.

212.02 Definitions.—The following terms and phrases when used in this chapter have the meanings ascribed to them in this section, except where the context clearly indicates a different meaning:

(26) "Solar energy system" means the equipment and requisite hardware that provide and are used for collecting, transferring, converting, storing, or using incident solar energy for water heating, space heating, cooling, or other applications that would otherwise require the use of a conventional source of energy such as petroleum products, natural gas, manufactured gas, or electricity.

TIP # 05A01-05
DATE ISSUED: June 1, 2005

SOLAR ENERGY SYSTEMS SALES AND USE TAX EXEMPTION NO LONGER SUBJECT TO REPEAL

Florida Law exempts from sales and use tax solar energy systems and all components of such systems. Previously set for repeal on July 1, 2005, the exemption's repeal date has been removed under an amendment to the law by the 2005 Florida Legislature. Accordingly, the exemption is no longer subject to an expiration date.

The term "solar energy system" means the equipment and requisite hardware that provide and are used for collecting, transferring, converting, storing, or using incidental solar energy for water heating, space heating and cooling, or other applications that would otherwise require the use of a conventional source of energy such as petroleum products, natural gas, manufactured gas, or electricity

A list of equipment and requisite hardware considered to be a solar energy system or component thereof is included for your reference.

Sellers of solar energy systems or components thereof are required to document exempt sales The following is a suggested form to be completed by the purchaser and presented to the seller

The undersigned hereby certifies that all equipment and requisite hardware purchased or leased on the attached order is purchased or leased for use exclusively in a solar energy system.

Purchaser's Name ______________________________

Address ______________________________

By ______________________________ Date __________

(signature)

References: Chapter 2005-83, Laws of Florida; Sections 212.02(26) and 212.08(7)(hh), Florida Statutes

FOR MORE INFORMATION

September 2003

The Florida Solar Energy Center certifies the following list to the Department of Revenue, pursuant to Section 212.08(7)(hh), Florida Statutes.

SOLAR ENERGY SYSTEM COMPONENTS

COLLECTOR: The purpose of a solar collector in thermal applications is to gather radiant energy from the sun and transfer it in the form of heat to a fluid for the purpose of domestic water heating, pool heating, space heating and cooling. A collector may consist of an absorber plate and tubing which may or may not be enclosed in an insulated box with a transparent cover. The collector provides the primary energy input to the system. Solar electric systems considered eligible for the exemption collect the light energy from the sun and convert it to electricity. A solar photovoltaic powered attic fan ventilation system is eligible. A pool blanket is eligible as a "passive" solar collector whether used in conjunction with or independently from an active solar pool system

TYPICAL MATERIALS: Cover plate - glass, resin - fiberglass, plastic, vinyl; Absorber and tubing - copper, galvanized steel, aluminum, plastic, rubber; Coating - non-selective, moderately selective, and selective; Insulation - polyisocyanurate, homasote, urethane, ductboards, fiberglass; Box - aluminum, galvanized steel, exterior grade wood, molded fiberglass; Photovoltaic Array - photovoltaic modules.

PUMP AND CONTROLS: The equipment which regulates the circulation of the fluid between the storage medium and the collector.

TYPICAL MATERIALS: Pump - bronze, brass, stainless steel, cast iron; Controller - solid state transistorized controller, sensors, timer, snap switches, and photovoltaic modules.

PHOTOVOLTAIC POWER CONDITIONING EQUIPMENT. The equipment which receives the direct current from the photovoltaic array, converts it to alternating current for consumption and/or transfer to the electric utility grid.

TYPICAL MATERIALS: Inverters, transformers, junction boxes, meters, maximum power trackers, dc to dc converters, and charge controllers.

STORAGE UNIT: The equipment which receives thermal energy, or direct current in the case of a solar electric system, and retains it for future use.

TYPICAL MATERIALS: Conventional tank, solar specific tank, tank equipped with heat exchanger, expansion tank, heat storage by phase change material, desiccants, batteries, regulators, mechanical housing and venting.

ACCESSORIES (when used as an integral part of a solar system): Piping, insulation, air vents, relief valves, mixing valves, check valves, gate valves, assorted bolts, nuts, washers and screws, mounting brackets, angle irons and other structural support (other than roof), solder, flux, pitch and pitch pans or other sealant, drain down reservoir, fans, air handling units, air dampers, heat exchangers, heat transfer fluids, convectors, radiators, pool blankets, direct current wiring, and miscellaneous safety equipment required for P.V. applications; for example, blocking and bypass diodes, surge arrestors, disconnect switches, fuse holders, fuses, relays, junction boxes, ground fault detector and/or interrupter, grounding hardware, and utility-interconnection protection equipment.

NOTE: Amount of piping allowable for the exemption is limited to that used in collector construction and the feed and return lines between collector and storage. Piping from the tank to the taps would be required in a conventional system and therefore is not eligible for an exemption. A typical or rule of thumb piping length for feed and return would be a total of 80 to 100 feet. Wiring used in photovoltaic applications considered eligible for the exemption is limited to that wiring which is unique to the system. Therefore, alternating current wiring throughout the structure which would be present without regard to the photovoltaic system is not eligible for the exemption. Tangible personal property in which the solar equipment is integral to the property (such as calculators, patio lights, appliances and novelty items), and where the cost of the solar equipment cannot be or is not separate from the total product cost, is not considered to be a solar energy system.

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Title XIV	Chapter 193	SECTION 624
TAXATION AND FINANCE	ASSESSMENTS	**Assessment of residential property.**
	Entire Chapter	

193.624 Assessment of residential property.—

(1) As used in this section, the term "renewable energy source device" means any of the following equipment that collects, transmits, stores, or uses solar energy, wind energy, or energy derived from geothermal deposits:

(a) Solar energy collectors, photovoltaic modules, and inverters.

(b) Storage tanks and other storage systems, excluding swimming pools used as storage tanks.

(c) Rockbeds.

(d) Thermostats and other control devices.

(e) Heat exchange devices.

(f) Pumps and fans.

(g) Roof ponds.

(h) Freestanding thermal containers.

(i) Pipes, ducts, refrigerant handling systems, and other equipment used to interconnect such systems; however, such equipment does not include conventional backup systems of any type.

(j) Windmills and wind turbines.

(k) Wind-driven generators.

(l) Power conditioning and storage devices that use wind energy to generate electricity or mechanical forms of energy.

(m) Pipes and other equipment used to transmit hot geothermal water to a dwelling or structure from a geothermal deposit.

(2) In determining the assessed value of real property used for residential purposes, an increase in the just value of the property attributable to the installation of a renewable energy source device may not be considered.

(3) This section applies to the installation of a renewable energy source device installed on or after January 1, 2013, to new and existing residential real property.

History.—s. 1, ch. 2013-77.

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Title XI COUNTY ORGANIZATION AND INTERGOVERNMENTAL RELATIONS	Chapter 163 INTERGOVERNMENTAL PROGRAMS Entire Chapter	**SECTION 04** **Energy devices based on renewable resources.**

163.04 Energy devices based on renewable resources.—

(1) Notwithstanding any provision of this chapter or other provision of general or special law, the adoption of an ordinance by a governing body, as those terms are defined in this chapter, which prohibits or has the effect of prohibiting the installation of solar collectors, clotheslines, or other energy devices based on renewable resources is expressly prohibited.

(2) A deed restriction, covenant, declaration, or similar binding agreement may not prohibit or have the effect of prohibiting solar collectors, clotheslines, or other energy devices based on renewable resources from being installed on buildings erected on the lots or parcels covered by the deed restriction, covenant, declaration, or binding agreement. A property owner may not be denied permission to install solar collectors or other energy devices by any entity granted the power or right in any deed restriction, covenant, declaration, or similar binding agreement to approve, forbid, control, or direct alteration of property with respect to residential dwellings and within the boundaries of a condominium unit. Such entity may determine the specific location where solar collectors may be installed on the roof within an orientation to the south or within 45° east or west of due south if such determination does not impair the effective operation of the solar collectors.

(3) In any litigation arising under the provisions of this section, the prevailing party shall be entitled to costs and reasonable attorney's fees.

(4) The legislative intent in enacting these provisions is to protect the public health, safety, and welfare by encouraging the development and use of renewable resources in order to conserve and protect the value of land, buildings, and resources by preventing the adoption of measures which will have the ultimate effect, however unintended, of driving the costs of owning and operating commercial or residential property beyond the capacity of private owners to maintain. This section shall not apply to patio railings in condominiums, cooperatives, or apartments.

History.—s. 8, ch. 80-163; s. 1, ch. 92-89; s. 14, ch. 93-249; s. 1, ch. 2008-191; s. 3, ch. 2008-227.

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Title XI COUNTY ORGANIZATION AND INTERGOVERNMENTAL RELATIONS	Chapter 163 INTERGOVERNMENTAL PROGRAMS Entire Chapter	**SECTION 08 Supplemental authority for improvements to real property.**

163.08 Supplemental authority for improvements to real property.—

(1)(a) In chapter 2008-227, Laws of Florida, the Legislature amended the energy goal of the state comprehensive plan to provide, in part, that the state shall reduce its energy requirements through enhanced conservation and efficiency measures in all end-use sectors and reduce atmospheric carbon dioxide by promoting an increased use of renewable energy resources. That act also declared it the public policy of the state to play a leading role in developing and instituting energy management programs that promote energy conservation, energy security, and the reduction of greenhouse gases. In addition to establishing policies to promote the use of renewable energy, the Legislature provided for a schedule of increases in energy performance of buildings subject to the Florida Energy Efficiency Code for Building Construction. In chapter 2008-191, Laws of Florida, the Legislature adopted new energy conservation and greenhouse gas reduction comprehensive planning requirements for local governments. In the 2008 general election, the voters of this state approved a constitutional amendment authorizing the Legislature, by general law, to prohibit consideration of any change or improvement made for the purpose of improving a property's resistance to wind damage or the installation of a renewable energy source device in the determination of the assessed value of residential real property.

(b) The Legislature finds that all energy-consuming-improved properties that are not using energy conservation strategies contribute to the burden affecting all improved property resulting from fossil fuel energy production. Improved property that has been retrofitted with energy-related qualifying improvements receives the special benefit of alleviating the property's burden from energy consumption. All improved properties not protected from wind damage by wind resistance qualifying improvements contribute to the burden affecting all improved property resulting from potential wind damage. Improved property that has been retrofitted with wind resistance qualifying improvements receives the special benefit of reducing the property's burden from potential wind damage. Further, the installation and operation of qualifying improvements not only benefit the affected properties for which the improvements are made, but also assist in fulfilling the goals of the state's energy and hurricane mitigation policies. In order to make qualifying improvements more affordable and assist property owners who wish to undertake such improvements, the Legislature finds that there is a compelling state interest in enabling property owners to voluntarily finance such improvements with local government assistance.

(c) The Legislature determines that the actions authorized under this section, including, but not limited to, the financing of qualifying improvements through the execution of financing agreements and the related imposition of voluntary assessments are reasonable and necessary to serve and achieve a compelling state interest and are necessary for the prosperity and welfare of the state and its property owners and inhabitants.

(2) As used in this section, the term:

(a) "Local government" means a county, a municipality, a dependent special district as defined in s. 189.012, or a separate legal entity created pursuant to s. 163.01(7).

(b) "Qualifying improvement" includes any:

1. Energy conservation and efficiency improvement, which is a measure to reduce consumption through conservation or a more efficient use of electricity, natural gas, propane, or other forms of energy on the property, including, but not limited to, air sealing; installation of insulation; installation of energy-efficient heating, cooling, or ventilation systems; building modifications to increase the use of daylight; replacement of windows; installation of

energy controls or energy recovery systems; installation of electric vehicle charging equipment; and installation of efficient lighting equipment.

2. Renewable energy improvement, which is the installation of any system in which the electrical, mechanical, or thermal energy is produced from a method that uses one or more of the following fuels or energy sources: hydrogen, solar energy, geothermal energy, bioenergy, and wind energy.

3. Wind resistance improvement, which includes, but is not limited to:

a. Improving the strength of the roof deck attachment;

b. Creating a secondary water barrier to prevent water intrusion;

c. Installing wind-resistant shingles;

d. Installing gable-end bracing;

e. Reinforcing roof-to-wall connections;

f. Installing storm shutters; or

g. Installing opening protections.

(3) A local government may levy non-ad valorem assessments to fund qualifying improvements.

(4) Subject to local government ordinance or resolution, a property owner may apply to the local government for funding to finance a qualifying improvement and enter into a financing agreement with the local government. Costs incurred by the local government for such purpose may be collected as a non-ad valorem assessment. A non-ad valorem assessment shall be collected pursuant to s. 197.3632 and, notwithstanding s. 197.3632(8)(a), shall not be subject to discount for early payment. However, the notice and adoption requirements of s. 197.3632(4) do not apply if this section is used and complied with, and the intent resolution, publication of notice, and mailed notices to the property appraiser, tax collector, and Department of Revenue required by s. 197.3632(3)(a) may be provided on or before August 15 in conjunction with any non-ad valorem assessment authorized by this section, if the property appraiser, tax collector, and local government agree.

(5) Pursuant to this section or as otherwise provided by law or pursuant to a local government's home rule power, a local government may enter into a partnership with one or more local governments for the purpose of providing and financing qualifying improvements.

(6) A qualifying improvement program may be administered by a for-profit entity or a not-for-profit organization on behalf of and at the discretion of the local government.

(7) A local government may incur debt for the purpose of providing such improvements, payable from revenues received from the improved property, or any other available revenue source authorized by law.

(8) A local government may enter into a financing agreement only with the record owner of the affected property. Any financing agreement entered into pursuant to this section or a summary memorandum of such agreement shall be recorded in the public records of the county within which the property is located by the sponsoring unit of local government within 5 days after execution of the agreement. The recorded agreement shall provide constructive notice that the assessment to be levied on the property constitutes a lien of equal dignity to county taxes and assessments from the date of recordation.

(9) Before entering into a financing agreement, the local government shall reasonably determine that all property taxes and any other assessments levied on the same bill as property taxes are paid and have not been delinquent for the preceding 3 years or the property owner's period of ownership, whichever is less; that there are no involuntary liens, including, but not limited to, construction liens on the property; that no notices of default or other evidence of property-based debt delinquency have been recorded during the preceding 3 years or the property owner's period of ownership, whichever is less; and that the property owner is current on all mortgage debt on the property.

(10) A qualifying improvement shall be affixed to a building or facility that is part of the property and shall constitute an improvement to the building or facility or a fixture attached to the building or facility. An agreement between a local government and a qualifying property owner may not cover wind-resistance improvements in buildings or facilities under new construction or construction for which a certificate of occupancy or similar evidence of substantial completion of new construction or improvement has not been issued.

(11) Any work requiring a license under any applicable law to make a qualifying improvement shall be performed by a contractor properly certified or registered pursuant to part I or part II of chapter 489.

(12)(a) Without the consent of the holders or loan servicers of any mortgage encumbering or otherwise secured by the property, the total amount of any non-ad valorem assessment for a property under this section may not exceed 20 percent of the just value of the property as determined by the county property appraiser.

(b) Notwithstanding paragraph (a), a non-ad valorem assessment for a qualifying improvement defined in subparagraph (2)(b)1. or subparagraph (2)(b)2. that is supported by an energy audit is not subject to the limits in this subsection if the audit demonstrates that the annual energy savings from the qualified improvement equals or exceeds the annual repayment amount of the non-ad valorem assessment.

(13) At least 30 days before entering into a financing agreement, the property owner shall provide to the holders or loan servicers of any existing mortgages encumbering or otherwise secured by the property a notice of the owner's intent to enter into a financing agreement together with the maximum principal amount to be financed and the maximum annual assessment necessary to repay that amount. A verified copy or other proof of such notice shall be provided to the local government. A provision in any agreement between a mortgagee or other lienholder and a property owner, or otherwise now or hereafter binding upon a property owner, which allows for acceleration of payment of the mortgage, note, or lien or other unilateral modification solely as a result of entering into a financing agreement as provided for in this section is not enforceable. This subsection does not limit the authority of the holder or loan servicer to increase the required monthly escrow by an amount necessary to annually pay the qualifying improvement assessment.

(14) At or before the time a purchaser executes a contract for the sale and purchase of any property for which a non-ad valorem assessment has been levied under this section and has an unpaid balance due, the seller shall give the prospective purchaser a written disclosure statement in the following form, which shall be set forth in the contract or in a separate writing:

QUALIFYING IMPROVEMENTS FOR ENERGY EFFICIENCY, RENEWABLE ENERGY, OR WIND RESISTANCE.—The property being purchased is located within the jurisdiction of a local government that has placed an assessment on the property pursuant to s. 163.08, Florida Statutes. The assessment is for a qualifying improvement to the property relating to energy efficiency, renewable energy, or wind resistance, and is not based on the value of property. You are encouraged to contact the county property appraiser's office to learn more about this and other assessments that may be provided by law.

(15) A provision in any agreement between a local government and a public or private power or energy provider or other utility provider is not enforceable to limit or prohibit any local government from exercising its authority under this section.

(16) This section is additional and supplemental to county and municipal home rule authority and not in derogation of such authority or a limitation upon such authority.

History.—s. 1, ch. 2010-139; s. 1, ch. 2012-117; s. 64, ch. 2014-22.

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Title XXVII	Chapter 366	SECTION 91
RAILROADS AND OTHER REGULATED UTILITIES	PUBLIC UTILITIES Entire Chapter	**Renewable energy.**

366.91 Renewable energy.—

(1) The Legislature finds that it is in the public interest to promote the development of renewable energy resources in this state. Renewable energy resources have the potential to help diversify fuel types to meet Florida's growing dependency on natural gas for electric production, minimize the volatility of fuel costs, encourage investment within the state, improve environmental conditions, and make Florida a leader in new and innovative technologies.

(2) As used in this section, the term:

(a) "Biomass" means a power source that is comprised of, but not limited to, combustible residues or gases from forest products manufacturing, waste, byproducts, or products from agricultural and orchard crops, waste or coproducts from livestock and poultry operations, waste or byproducts from food processing, urban wood waste, municipal solid waste, municipal liquid waste treatment operations, and landfill gas.

(b) "Customer-owned renewable generation" means an electric generating system located on a customer's premises that is primarily intended to offset part or all of the customer's electricity requirements with renewable energy.

(c) "Net metering" means a metering and billing methodology whereby customer-owned renewable generation is allowed to offset the customer's electricity consumption on site.

(d) "Renewable energy" means electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power. The term includes the alternative energy resource, waste heat, from sulfuric acid manufacturing operations and electrical energy produced using pipeline-quality synthetic gas produced from waste petroleum coke with carbon capture and sequestration.

(3) On or before January 1, 2006, each public utility must continuously offer a purchase contract to producers of renewable energy. The commission shall establish requirements relating to the purchase of capacity and energy by public utilities from renewable energy producers and may adopt rules to administer this section. The contract shall contain payment provisions for energy and capacity which are based upon the utility's full avoided costs, as defined in s. 366.051; however, capacity payments are not required if, due to the operational characteristics of the renewable energy generator or the anticipated peak and off-peak availability and capacity factor of the utility's avoided unit, the producer is unlikely to provide any capacity value to the utility or the electric grid during the contract term. Each contract must provide a contract term of at least 10 years. Prudent and reasonable costs associated with a renewable energy contract shall be recovered from the ratepayers of the contracting utility, without differentiation among customer classes, through the appropriate cost-recovery clause mechanism administered by the commission.

(4) On or before January 1, 2006, each municipal electric utility and rural electric cooperative whose annual sales, as of July 1, 1993, to retail customers were greater than 2,000 gigawatt hours must continuously offer a purchase contract to producers of renewable energy containing payment provisions for energy and capacity which are based upon the utility's or cooperative's full avoided costs, as determined by the governing body of the municipal utility or cooperative; however, capacity payments are not required if, due to the operational characteristics of the renewable energy generator or the anticipated peak and off-peak availability and capacity factor of the utility's avoided unit, the producer is unlikely to provide any capacity value to the utility or the electric grid during the contract term. Each contract must provide a contract term of at least 10 years.

(5) On or before January 1, 2009, each public utility shall develop a standardized interconnection agreement and net metering program for customer-owned renewable generation. The commission shall establish requirements relating to the expedited interconnection and net metering of customer-owned renewable generation by public utilities and may adopt rules to administer this section.

(6) On or before July 1, 2009, each municipal electric utility and each rural electric cooperative that sells electricity at retail shall develop a standardized interconnection agreement and net metering program for customer-owned renewable generation. Each governing authority shall establish requirements relating to the expedited interconnection and net metering of customer-owned generation. By April 1 of each year, each municipal electric utility and rural electric cooperative utility serving retail customers shall file a report with the commission detailing customer participation in the interconnection and net metering program, including, but not limited to, the number and total capacity of interconnected generating systems and the total energy net metered in the previous year.

(7) Under the provisions of subsections (5) and (6), when a utility purchases power generated from biogas produced by the anaerobic digestion of agricultural waste, including food waste or other agricultural byproducts, net metering shall be available at a single metering point or as a part of conjunctive billing of multiple points for a customer at a single location, so long as the provision of such service and its associated charges, terms, and other conditions are not reasonably projected to result in higher cost electric service to the utility's general body of ratepayers or adversely affect the adequacy or reliability of electric service to all customers, as determined by the commission for public utilities, or as determined by the governing authority of the municipal electric utility or rural electric cooperative that serves at retail.

(8) A contracting producer of renewable energy must pay the actual costs of its interconnection with the transmission grid or distribution system.

History.—s. 1, ch. 2005-259; s. 41, ch. 2008-227; s. 16, ch. 2010-139.

The Florida Senate

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Title XXVIII NATURAL RESOURCES; CONSERVATION, RECLAMATION, AND USE	Chapter 377 ENERGY RESOURCES Entire Chapter	**SECTION 705 Solar Energy Center; development of solar energy standards.**

377.705 Solar Energy Center; development of solar energy standards.—

(1) SHORT TITLE.—This act shall be known and may be cited as the Solar Energy Standards Act of 1976.

(2) LEGISLATIVE FINDINGS AND INTENT.—

(a) Because of increases in the cost of conventional fuel, certain applications of solar energy are becoming competitive, particularly when life-cycle costs are considered. It is the intent of the Legislature in formulating a sound and balanced energy policy for the state to encourage the development of an alternative energy capability in the form of incident solar energy.

(b) Toward this purpose, the Legislature intends to provide incentives for the production and sale of, and to set standards for, solar energy systems. Such standards shall ensure that solar energy systems manufactured or sold within the state are effective and represent a high level of quality of materials, workmanship, and design.

(3) DEFINITIONS.—

(a) "Center" is defined as the Florida Solar Energy Center of the Board of Governors.

(b) "Solar energy systems" is defined as equipment which provides for the collection and use of incident solar energy for water heating, space heating or cooling, or other applications which normally require or would require a conventional source of energy such as petroleum products, natural gas, or electricity and which performs primarily with solar energy. In such other systems in which solar energy is used in a supplemental way, only those components which collect and transfer solar energy shall be included in this definition.

(4) FLORIDA SOLAR ENERGY CENTER TO SET STANDARDS, REQUIRE DISCLOSURE, SET TESTING FEES.—

(a) The center shall develop and promulgate standards for solar energy systems manufactured or sold in this state based on the best currently available information and shall consult with scientists, engineers, or persons in research centers who are engaged in the construction of, experimentation with, and research of solar energy systems to properly identify the most reliable designs and types of solar energy systems.

(b) The center shall establish criteria for testing performance of solar energy systems and shall maintain the necessary capability for testing or evaluating performance of solar energy systems. The center may accept results of tests on solar energy systems made by other organizations, companies, or persons when such tests are conducted according to the criteria established by the center and when the testing entity has no vested interest in the manufacture, distribution or sale of solar energy systems.

(c) The center shall be entitled to receive a testing fee sufficient to cover the costs of such testing. All testing fees shall be transmitted by the center to the Chief Financial Officer to be deposited in the Solar Energy Center Testing Trust Fund, which is hereby created in the State Treasury, and disbursed for the payment of expenses incurred in testing solar energy systems.

(d) All solar energy systems manufactured or sold in the state must meet the standards established by the center and shall display accepted results of approved performance tests in a manner prescribed by the center.

History.—ss. 1, 2, 3, 4, ch. 76-246; s. 1, ch. 78-309; s. 400, ch. 2003-261; s. 45, ch. 2007-217; s. 56, ch. 2008-227.

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Title XXIX PUBLIC HEALTH	Chapter 403 ENVIRONMENTAL CONTROL Entire Chapter	**SECTION 503** **Definitions relating to Florida Electrical Power Plant Siting Act.**

403.503 Definitions relating to Florida Electrical Power Plant Siting Act.—As used in this act:

(1) "Act" means the Florida Electrical Power Plant Siting Act.

(2) "Agency," as the context requires, means an official, officer, commission, authority, council, committee, department, division, bureau, board, section, or other unit or entity of government, including a regional or local governmental entity.

(3) "Alternate corridor" means an area that is proposed by the applicant or a third party within which all or part of an associated electrical transmission line right-of-way is to be located and that is different from the preferred transmission line corridor proposed by the applicant. The width of the alternate corridor proposed for certification for an associated electrical transmission line may be the width of the proposed right-of-way or a wider boundary not to exceed a width of 1 mile. The area within the alternate corridor may be further restricted as a condition of certification. The alternate corridor may include alternate electrical substation sites if the applicant has proposed an electrical substation as part of the portion of the proposed electrical transmission line.

(4) "Amendment" means a material change in the information provided by the applicant to the application for certification made after the initial application filing.

(5) "Applicant" means any electric utility which applies for certification pursuant to the provisions of this act.

(6) "Application" means the documents required by the department to be filed to initiate a certification review and evaluation, including the initial document filing, amendments, and responses to requests from the department for additional data and information.

(7) "Associated facilities" means, for the purpose of certification, those onsite and offsite facilities which directly support the construction and operation of the electrical power plant such as electrical transmission lines, substations, and fuel unloading facilities; pipelines necessary for transporting fuel for the operation of the facility or other fuel transportation facilities; water or wastewater transport pipelines; construction, maintenance, and access roads; and railway lines necessary for transport of construction equipment or fuel for the operation of the facility.

(8) "Board" means the Governor and Cabinet sitting as the siting board.

(9) "Certification" means the written order of the board, or secretary when applicable, approving an application for the licensing of an electrical power plant, in whole or with such changes or conditions as the board may deem appropriate.

(10) "Completeness" means that the application has addressed all applicable sections of the prescribed application format, and that those sections are sufficient in comprehensiveness of data or in quality of information provided to allow the department to determine whether the application provides the reviewing agencies adequate information to prepare the reports required by s. 403.507.

(11) "Corridor" means the proposed area within which an associated linear facility right-of-way is to be located. The width of the corridor proposed for certification as an associated facility, at the option of the applicant, may be the width of the right-of-way or a wider boundary, not to exceed a width of 1 mile. The area within the corridor in which a right-of-way may be located may be further restricted by a condition of certification. After all property interests required for the right-of-way have been acquired by the licensee, the boundaries of the area certified shall narrow to only that land within the boundaries of the right-of-way. The corridors proper for certification shall be those addressed in the application, in amendments to the application filed under s. 403.5064, and in notices of acceptance of proposed alternate corridors filed by an applicant and the department pursuant to s. 403.5271 as incorporated by

reference in s. 403.5064(1)(b) for which the required information for the preparation of agency supplemental reports was filed.

(12) "Department" means the Department of Environmental Protection.

(13) "Designated administrative law judge" means the administrative law judge assigned by the Division of Administrative Hearings pursuant to chapter 120 to conduct the hearings required by this act.

(14) "Electrical power plant" means, for the purpose of certification, any steam or solar electrical generating facility using any process or fuel, including nuclear materials, except that this term does not include any steam or solar electrical generating facility of less than 75 megawatts in capacity unless the applicant for such a facility elects to apply for certification under this act. This term also includes the site; all associated facilities that will be owned by the applicant that are physically connected to the site; all associated facilities that are indirectly connected to the site by other proposed associated facilities that will be owned by the applicant; and associated transmission lines that will be owned by the applicant which connect the electrical power plant to an existing transmission network or rights-of-way to which the applicant intends to connect. At the applicant's option, this term may include any offsite associated facilities that will not be owned by the applicant; offsite associated facilities that are owned by the applicant but that are not directly connected to the site; any proposed terminal or intermediate substations or substation expansions connected to the associated transmission line; or new transmission lines, upgrades, or improvements of an existing transmission line on any portion of the applicant's electrical transmission system necessary to support the generation injected into the system from the proposed electrical power plant.

(15) "Electric utility" means cities and towns, counties, public utility districts, regulated electric companies, electric cooperatives, and joint operating agencies, or combinations thereof, engaged in, or authorized to engage in, the business of generating, transmitting, or distributing electric energy.

(16) "Federally delegated or approved permit program" means any environmental regulatory program approved by an agency of the Federal Government so as to authorize the department to administer and issue licenses pursuant to federal law, including, but not limited to, new source review permits, operation permits for major sources of air pollution, and prevention of significant deterioration permits under the Clean Air Act (42 U.S.C. ss. 7401 et seq.), permits under ss. 402 and 404 of the Clean Water Act (33 U.S.C. ss. 1251 et seq.), and permits under the Resource Conservation and Recovery Act (42 U.S.C. ss. 6901 et seq.).

(17) "License" means a franchise, permit, certification, registration, charter, comprehensive plan amendment, development order or permit as defined in chapters 163 and 380, or similar form of authorization required by law, including permits issued under federally delegated or approved permit programs, but it does not include a license required primarily for revenue purposes when issuance of the license is merely a ministerial act.

(18) "Licensee" means an applicant that has obtained a certification order for the subject project.

(19) "Local government" means a municipality or county in the jurisdiction of which the electrical power plant is proposed to be located.

(20) "Modification" means any change in the certification order after issuance, including a change in the conditions of certification.

(21) "Nonprocedural requirements of agencies" means any agency's regulatory requirements established by statute, rule, ordinance, zoning ordinance, land development code, or comprehensive plan, excluding any provisions prescribing forms, fees, procedures, or time limits for the review or processing of information submitted to demonstrate compliance with such regulatory requirements.

(22) "Notice of intent" means that notice which is filed with the department on behalf of an applicant prior to submission of an application pursuant to this act and which notifies the department of an intent to file an application.

(23) "Person" means an individual, partnership, joint venture, private or public corporation, association, firm, public service company, political subdivision, municipal corporation, government agency, public utility district, or any other entity, public or private, however organized.

(24) "Preliminary statement of issues" means a listing and explanation of those issues within the agency's jurisdiction which are of major concern to the agency in relation to the proposed electrical power plant.

(25) “Public Service Commission” or “commission” means the agency created pursuant to chapter 350.

(26) “Regional planning council” means a regional planning council as defined in s. 186.503(4) in the jurisdiction of which the electrical power plant is proposed to be located.

(27) “Right-of-way” means land necessary for the construction and maintenance of a connected associated linear facility, such as a railroad line, pipeline, or transmission line as owned by or proposed to be certified by the applicant. The typical width of the right-of-way shall be identified in the application. The right-of-way shall be located within the certified corridor and shall be identified by the applicant subsequent to certification in documents filed with the department prior to construction.

(28) “Site” means any proposed location within which will be located an electrical power plant’s generating facility and onsite support facilities, or an alteration or addition of electrical generating facilities and onsite support facilities resulting in an increase in generating capacity, including offshore sites within state jurisdiction.

(29) “State comprehensive plan” means that plan set forth in chapter 187.

(30) “Ultimate site capacity” means the maximum gross generating capacity for a site as certified by the board, unless otherwise specified as net generating capacity.

(31) “Water management district” means a water management district, created pursuant to chapter 373, in the jurisdiction of which the electrical power plant is proposed to be located.

History.—s. 1, ch. 73-33; s. 1, ch. 76-76; s. 1, ch. 79-76; s. 3, ch. 81-131; s. 14, ch. 86-173; s. 22, ch. 86-186; s. 3, ch. 90-331; s. 6, ch. 93-94; s. 383, ch. 94-356; s. 134, ch. 96-410; s. 20, ch. 2006-230; s. 67, ch. 2008-227.

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Title XII MUNICIPALITIES	Chapter 166 MUNICIPALITIES Entire Chapter	**SECTION 231 Municipalities; public service tax.**

166.231 Municipalities; public service tax.—

(1)(a) A municipality may levy a tax on the purchase of electricity, metered natural gas, liquefied petroleum gas either metered or bottled, manufactured gas either metered or bottled, and water service. Except for those municipalities in which paragraph (c) applies, the tax shall be levied only upon purchases within the municipality and shall not exceed 10 percent of the payments received by the seller of the taxable item from the purchaser for the purchase of such service. Municipalities imposing a tax on the purchase of cable television service as of May 4, 1977, may continue to levy such tax to the extent necessary to meet all obligations to or for the benefit of holders of bonds or certificates which were issued prior to May 4, 1977. Purchase of electricity means the purchase of electric power by a person who will consume it within the municipality.

(b) The tax imposed by paragraph (a) shall not be applied against any fuel adjustment charge, and such charge shall be separately stated on each bill. The term "fuel adjustment charge" means all increases in the cost of utility services to the ultimate consumer resulting from an increase in the cost of fuel to the utility subsequent to October 1, 1973.

(c) The tax in paragraph (a) on water service may be applied outside municipal boundaries to property included in a development of regional impact approved pursuant to s. 380.06, if agreed to in writing by the developer of such property and the municipality prior to March 31, 2000. If a tax levied pursuant to the subsection is challenged, recovery, if any, shall be limited to moneys paid into an escrow account of the clerk of the court subsequent to such challenge.

(2) Services competitive with those enumerated in subsection (1), as defined by ordinance, shall be taxed on a comparable base at the same rates. However, fuel oil shall be taxed at a rate not to exceed 4 cents per gallon. However, for municipalities levying less than the maximum rate allowable in subsection (1), the maximum tax on fuel oil shall bear the same proportion to 4 cents which the tax rate levied under subsection (1) bears to the maximum rate allowable in subsection (1).

(3) A municipality may exempt from the tax imposed by this section any amount up to, and including, the first 500 kilowatt hours of electricity purchased per month for residential use. Such exemption shall apply to each separate residential unit, regardless of whether such unit is on a separate meter or a central meter, and shall be passed on to each individual tenant.

(4)(a) The purchase of natural gas, manufactured gas, or fuel oil by a public or private utility, either for resale or for use as fuel in the generation of electricity, or the purchase of fuel oil or kerosene for use as an aircraft engine fuel or propellant or for use in internal combustion engines is exempt from taxation hereunder.

(b) A municipality may exempt from the tax imposed by this section the purchase of metered or bottled gas (natural liquefied petroleum gas or manufactured) or fuel oil for agricultural purposes. As used in this paragraph, "agricultural purposes" means bona fide farming, pasture, grove, or forestry operations, including horticulture, floriculture, viticulture, dairy, livestock, poultry, bee, and aquaculture.

(5) Purchases by the United States Government, this state, and all counties, school districts, and municipalities of the state, and by public bodies exempted by law or court order, are exempt from the tax authorized by this section. A municipality may exempt from the tax imposed by this section the purchase of taxable items by any other public body as defined in s. 1.01, or by a nonprofit corporation or cooperative association organized under chapter 617 which provides water utility services to no more than 13,500 equivalent residential units, ownership of which will revert to a

political subdivision upon retirement of all outstanding indebtedness, and shall exempt purchases by any recognized church in this state for use exclusively for church purposes.

(6) A municipality may exempt from the tax imposed by this section any amount up to, and including, the total amount of electricity, metered natural gas, liquefied petroleum gas either metered or bottled, or manufactured gas either metered or bottled purchased per month, or reduce the rate of taxation on the purchase of such electricity or gas when purchased by an industrial consumer which uses the electricity or gas directly in industrial manufacturing, processing, compounding, or a production process, at a fixed location in the municipality, of items of tangible personal property for sale. The municipality shall establish the requirements for qualification for this exemption in the manner prescribed by ordinance. Possession by a seller of a written certification by the purchaser, certifying the purchaser's entitlement to an exemption permitted by this subsection, relieves the seller from the responsibility of collecting the tax on the nontaxable amounts, and the municipality shall look solely to the purchaser for recovery of such tax if it determines that the purchaser was not entitled to the exemption. Any municipality granting an exemption pursuant to this subsection shall grant the exemption to all companies classified in the same five-digit NAICS Industry Number. As used in this subsection, "NAICS" means those classifications contained in the North American Industry Classification System, as published in 2007 by the Office of Management and Budget, Executive Office of the President.

(7) The tax authorized hereunder shall be collected by the seller of the taxable item from the purchaser at the time of the payment for such service. The seller shall remit the taxes collected to the municipality in the manner prescribed by ordinance. Except as otherwise provided in ss. 166.233 and 166.234, the seller shall be liable for taxes that are due and not remitted to the municipality. This shall not bar the seller from recovering such taxes from purchasers; however, the universities in the State University System shall not be deemed a seller of any item otherwise taxable hereunder when such item is provided to university residences incidental to the provision of educational services.

(8)(a) Beginning July 1, 1995, a municipality may by ordinance exempt not less than 50 percent of the tax imposed under this section on purchasers of electrical energy who are determined to be eligible for the exemption provided by s. 212.08(15) by the Department of Revenue. The exemption shall be administered as provided in that section. A copy of any ordinance adopted pursuant to this subsection shall be provided to the Department of Revenue not less than 14 days prior to its effective date.

(b) If an area that is nominated as an enterprise zone pursuant to s. 290.0055 has not yet been designated pursuant to s. 290.0065, a municipality may enact an ordinance for such exemption; however, the ordinance shall not be effective until such area is designated pursuant to s. 290.0065.

(c) This subsection expires on the date specified in s. 290.016 for the expiration of the Florida Enterprise Zone Act, except that any qualified business that has satisfied the requirements of this subsection before that date shall be allowed the full benefit of the exemption allowed under this subsection as if this subsection had not expired on that date.

(9) A purchaser who claims an exemption under subsection (4) or subsection (5) shall certify to the seller that he or she qualifies for the exemption, which certification may encompass all purchases after a specified date or other multiple purchases. A seller accepting the certification required by this subsection is relieved of the obligation to collect and remit tax; however, a governmental body that is exempt from the tax authorized by this section shall not be required to furnish such certification, and a seller is not required to collect tax from such an exempt governmental body.

(10) Governmental bodies which sell or resell taxable service to nonexempt end users must collect and remit the tax levied under this section.

History.—s. 1, ch. 73-129; ss. 1, 2, ch. 74-109; s. 1, ch. 77-174; s. 1, ch. 77-251; s. 4, ch. 78-299; s. 1, ch. 78-400; s. 1, ch. 82-230; s. 1, ch. 82-399; s. 24, ch. 84-356; s. 1, ch. 85-174; s. 1, ch. 86-155; s. 1, ch. 88-35; s. 1, ch. 88-140; s. 36, ch. 90-360; s. 1, ch. 93-224; s. 44, ch. 94-136; s. 1, ch. 95-403; s. 12, ch. 96-320; s. 47, ch. 96-406; s. 2, ch. 97-233; s. 2, ch. 97-283; s. 10, ch. 98-277; s. 64, ch. 99-2; s. 18, ch. 2000-158; ss. 36, 38, 58, ch. 2000-260; s. 5, ch. 2000-355; s. 28, ch. 2001-60; s. 38, ch. 2001-140; s. 2, ch. 2003-17; s. 13, ch. 2005-287; s. 2, ch. 2009-51.

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Title XXVII RAILROADS AND OTHER REGULATED UTILITIES	Chapter 366 PUBLIC UTILITIES **Entire Chapter**	**SECTION 14** **Regulatory assessment fees.**

366.14 Regulatory assessment fees.—Notwithstanding any provision of law to the contrary, each regulated company under the jurisdiction of the commission which was in operation for any part of the preceding 6-month period shall pay to the commission within 30 days following the end of each 6-month period a fee based upon its gross operating revenues for that period. The fee may not be greater than:

(1) For each public utility that supplies electricity, 0.125 percent of its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities, municipal electric utilities, and rural electric cooperatives or any combination thereof;

(2) For each public utility that supplies gas (natural, manufactured, or similar gaseous substance), 0.5 percent of its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities and municipal gas utilities or any combination thereof;

(3) For each municipal gas utility or gas district, 0.25 percent of its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities and municipal gas utilities or any combination thereof; and

(4) For each municipal electric utility or rural electric cooperative, 0.015625 percent of its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities, municipal electric utilities, or rural electric cooperatives or any combination thereof.

History.—ss. 16, 22, ch. 89-292; s. 4, ch. 91-429.

25-6.065 Interconnection and Net Metering of Customer-Owned Renewable Generation.

(1) Application and Scope. The purpose of this rule is to promote the development of small customer-owned renewable generation, particularly solar and wind energy systems; diversify the types of fuel used to generate electricity in Florida; lessen Florida's dependence on fossil fuels for the production of electricity; minimize the volatility of fuel costs; encourage investment in the state; improve environmental conditions; and, at the same time, minimize costs of power supply to investor-owned utilities and their customers. This rule applies to all investor-owned utilities, except as otherwise stated in subsection (10).

(2) Definitions. As used in this rule, the term.

(a) "Customer-owned renewable generation" means an electric generating system located on a customer's premises that is primarily intended to offset part or all of the customer's electricity requirements with renewable energy. The term "customer-owned renewable generation" does not preclude the customer of record from contracting for the purchase, lease, operation, or maintenance of an on-site renewable generation system with a third-party under terms and conditions that do not include the retail purchase of electricity from the third party.

(b) "Gross power rating" means the total manufacturer's AC nameplate generating capacity of an on-site customer-owned renewable generation system that will be interconnected to and operate in parallel with the investor-owned utility's distribution facilities. For inverter-based systems, the AC nameplate generating capacity shall be calculated by multiplying the total installed DC nameplate generating capacity by .85 in order to account for losses during the conversion from DC to AC.

(c) "Net metering" means a metering and billing methodology whereby customer-owned renewable generation is allowed to offset the customer's electricity consumption on-site.

(d) "Renewable energy," as defined in Section 377.803, F.S., means electrical, mechanical, or thermal energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen, biomass, solar energy, geothermal energy, wind energy, ocean energy, waste heat, or hydroelectric power.

(3) Standard Interconnection Agreements. Each investor-owned utility shall, within 30 days of the effective date of this rule, file for Commission approval a Standard Interconnection Agreement for expedited interconnection of customer-owned renewable generation, up to 2 MW, that complies with the following standards:

(a) IEEE 1547 (2003) Standard for Interconnecting Distributed Resources with Electric Power Systems;

(b) IEEE 1547.1 (2005) Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems; and

(c) UL 1741 (2005) Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.

(d) A copy of IEEE 1547 (2003), ISBN number 0-7381-3720-0, and IEEE 1547.1 (2005), ISBN number 0-7381-4737-0, may be obtained from the Institute of Electric and Electronic Engineers, Inc. (IEEE), 3 Park Avenue, New York, NY, 10016-5997. A copy of UL 1741 (2005) may be obtained from COMM 2000, 1414 Brook Drive, Downers Grove, IL 60515.

(4) Customer Qualifications and Fees.

(a) To qualify for expedited interconnection under this rule, customer-owned renewable generation must have a gross power rating that:

1. Does not exceed 90% of the customer's utility distribution service rating; and

2. Falls within one of the following ranges:

Tier 1 – 10 kW or less;

Tier 2 – greater than 10 kW and less than or equal to 100 kW; or

Tier 3 – greater than 100 kW and less than or equal to 2 MW.

(b) Customer-owned renewable generation shall be considered certified for interconnected operation if it has been submitted by a manufacturer to a nationally recognized testing and certification laboratory, and has been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed in subsection (3).

(c) Customer-owned renewable generation shall include a utility-interactive inverter, or other device certified pursuant to paragraph (4)(b) that performs the function of automatically isolating the customer-owned generation equipment from the electric grid in the event the electric grid loses power.

(d) For Tiers 1 and 2, provided the customer-owned renewable generation equipment complies with paragraphs (4)(a) and (b), the investor-owned utility shall not require further design review, testing, or additional equipment other than that provided for in subsection (6). For Tier 3, if an interconnection study is necessary, further design review, testing and additional equipment as identified in the study may be required.

(e) Tier 1 customers who request interconnection of customer-owned renewable generation shall not be charged fees in addition to those charged to other retail customers without self-generation, including application fees.

(f) Along with the Standard Interconnection Agreement filed pursuant to subsection (3), each investor-owned utility may propose for Commission approval a standard application fee for Tiers 2 and 3, including itemized cost support for each cost contained within the fee.

(g) Each investor-owned utility may also propose for Commission approval an Interconnection Study Charge for Tier 3.

(h) Each investor-owned utility shall show that their fees and charges are cost-based and reasonable. No fees or charges shall be assessed for interconnecting customer-owned renewable generation without prior Commission approval.

(5) Contents of Standard Interconnection Agreement. Each investor-owned utility's customer-owned renewable generation Standard Interconnection Agreement shall, at a minimum, contain the following:

(a) A requirement that customer-owned renewable generation must be inspected and approved by local code officials prior to its operation in parallel with the investor-owned utility to ensure compliance with applicable local codes.

(b) Provisions that permit the investor-owned utility to inspect customer-owned renewable generation and its component equipment, and the documents necessary to ensure compliance with subsections (2) through (4). The customer shall notify the investor-owned utility at least 10 days prior to initially placing customer equipment and protective apparatus in service, and the investor-owned utility shall have the right to have personnel present on the in-service date. If the customer-owned renewable generation system is subsequently modified in order to increase its gross power rating, the customer must notify the investor-owned utility by submitting a new application specifying the modifications at least 30 days prior to making the modifications.

(c) A provision that the customer is responsible for protecting the renewable generating equipment, inverters, protective devices, and other system components from damage from the normal and abnormal conditions and operations that occur on the investor-owned utility system in delivering and restoring power; and is responsible for ensuring that customer-owned renewable generation equipment is inspected, maintained, and tested in accordance with the manufacturer's instructions to ensure that it is operating correctly and safely.

(d) A provision that the customer shall hold harmless and indemnify the investor-owned utility for all loss to third parties resulting from the operation of the customer-owned renewable generation, except when the loss occurs due to the negligent actions of the investor-owned utility. A provision that the investor-owned utility shall hold harmless and indemnify the customer for all loss to third parties resulting from the operation of the investor-owned utility's system, except when the loss occurs due to the negligent actions of the customer.

(e) A requirement for general liability insurance for personal and property damage, or sufficient guarantee and proof of self-insurance, in the amount of no more than $1 million for Tier 2, and no more than $2 million for Tier 3. The investor-owned utility shall not require liability insurance for Tier 1. The investor-owned utility may include in the Interconnection Agreement a recommendation that Tier 1 customers carry an appropriate level of liability insurance.

(f) Identification of any fees or charges approved pursuant to subsection (4).

(6) Manual Disconnect Switch.

(a) Each investor-owned utility's customer-owned renewable generation Standard Interconnection Agreement may require customers to install, at the customer's expense, a manual disconnect switch of the visible load break type to provide a separation point between the AC power output of the customer-owned renewable generation and any customer wiring connected to the investor-owned utility's system. Inverter-based Tier 1 customer-owned renewable generation systems shall be exempt from this requirement, unless the manual disconnect switch is installed at the investor-owned utility's expense. The manual disconnect switch shall be mounted separate from, but adjacent to, the meter socket and shall be readily accessible to the investor-owned utility and capable of being locked in the open position with a single investor-owned utility padlock.

(b) The investor-owned utility may open the switch pursuant to the conditions set forth in paragraph (6)(c), isolating the customer-owned renewable generation, without prior notice to the customer. To the extent practicable, however, prior notice shall be given. If prior notice is not given, the utility shall at the time of disconnection leave a door hanger notifying the customer that their customer-owned renewable generation has been disconnected, including an explanation of the condition necessitating such action. The investor-owned utility shall reconnect the customer-owned renewable generation as soon as the condition necessitating disconnection is remedied.

(c) Any of the following conditions shall be cause for the investor-owned utility to disconnect customer-owned renewable generation from its system:

1. Emergencies or maintenance requirements on the investor-owned utility's electric system;

2. Hazardous conditions existing on the investor-owned utility system due to the operation of the customer's generating or protective equipment as determined by the investor-owned utility;

3. Adverse electrical effects, such as power quality problems, on the electrical equipment of the investor-owned utility's other electric consumers caused by the customer-owned renewable generation as determined by the investor-owned utility;

4. Failure of the customer to maintain the required insurance coverage.

(7) Administrative Requirements.

(a) Each investor-owned utility shall maintain on its website a downloadable application for interconnection of customer-owned renewable generation, detailing the information necessary to execute the Standard Interconnection Agreement. Upon request the investor-owned utility shall provide a hard copy of the application within 5 business days.

(b) Within 10 business days of receipt of the customer's application, the investor-owned utility shall provide written notice that it has received all documents required by the Standard Interconnection Agreement or indicate how the application is deficient. Within 10 business days of receipt of a completed application, the utility shall provide written notice verifying receipt of the completed application. The written notice shall also include dates for any physical inspection of the customer-owned renewable generation necessary for the investor-owned utility to confirm compliance with subsections (2) through (6), and confirmation of whether a Tier 3 interconnection study will be necessary.

(c) The Standard Interconnection Agreement shall be executed by the investor-owned utility within 30 calendar days of receipt of a completed application. If the investor-owned utility determines that an interconnection study is necessary for a Tier 3 customer, the investor-owned utility shall execute the Standard Interconnection Agreement within 90 days of a completed application.

(d) The customer must execute the Standard Interconnection Agreement and return it to the investor-owned utility at least 30 calendar days prior to beginning parallel operations and within one year after the utility executes the Agreement. All physical inspections must be completed by the utility within 30 calendar days of receipt of the customer's executed Standard Interconnection Agreement. If the inspection is delayed at the customer's request, the customer shall contact the utility to reschedule an inspection. The investor-owned utility shall reschedule the inspection within 10 business days of the customer's request.

(8) Net Metering.

(a) Each investor-owned utility shall enable each customer-owned renewable generation facility interconnected to the investor-owned utility's electrical grid pursuant to this rule to net meter.

(b) Each investor-owned utility shall install, at no additional cost to the customer, metering equipment at the point of delivery capable of measuring the difference between the electricity supplied to the customer from the investor-owned utility and the electricity generated by the customer and delivered to the investor-owned utility's electric grid.

(c) Meter readings shall be taken monthly on the same cycle as required under the otherwise applicable rate schedule.

(d) The investor-owned utility shall charge for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation in accordance with normal billing practices.

(e) During any billing cycle, excess customer-owned renewable generation delivered to the investor-owned utility's electric grid shall be credited to the customer's energy consumption for the next month's billing cycle.

(f) Energy credits produced pursuant to paragraph (8)(e) shall accumulate and be used to offset the customer's energy usage in subsequent months for a period of not more than twelve months. At the end of each calendar year, the investor-owned utility shall pay the customer for any unused energy credits at an average annual rate based on the investor-owned utility's COG-1, as-available energy tariff.

(g) When a customer leaves the system, that customer's unused credits for excess kWh generated shall be paid to the customer at an average annual rate based on the investor-owned utility's COG-1, as-available energy tariff.

(h) Regardless of whether excess energy is delivered to the investor-owned utility's electric grid, the customer shall continue to pay the applicable customer charge and applicable demand charge for the maximum measured demand during the billing period. The investor-owned utility shall charge for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation at the investor-owned utility's otherwise applicable rate schedule. The customer may at their sole discretion choose to take service under the investor-owned utility's standby or supplemental service rate, if available.

(9) Renewable Energy Certificates. Customers shall retain any Renewable Energy Certificates associated with the electricity

produced by their customer-owned renewable generation equipment. Any additional meters necessary for measuring the total renewable electricity generated for the purposes of receiving Renewable Energy Certificates shall be installed at the customer's expense, unless otherwise determined during negotiations for the sale of the customer's Renewable Energy Certificates to the investor-owned utility.

(10) Reporting Requirements. Each electric utility, as defined in Section 366.02(2), F.S., shall file with the Commission as part of its tariff a copy of its Standard Interconnection Agreement form for customer-owned renewable generation. In addition, each electric utility shall report the following, by April 1 of each year.

(a) Total number of customer-owned renewable generation interconnections as of the end of the previous calendar year;

(b) Total kW capacity of customer-owned renewable generation interconnected as of the end of the previous calendar year;

(c) Total kWh received by interconnected customers from the electric utility, by month and by year for the previous calendar year;

(d) Total kWh of customer-owned renewable generation delivered to the electric utility, by month and by year for the previous calendar year; and

(e) Total energy payments made to interconnected customers for customer-owned renewable generation delivered to the electric utility for the previous calendar year, along with the total payments made since the implementation of this rule.

(f) For each individual customer-owned renewable generation interconnection:

1. Renewable technology utilized;

2. Gross power rating;

3. Geographic location by county; and

4. Date interconnected.

(11) Dispute Resolution. Parties may seek resolution of disputes arising out of the interpretation of this rule pursuant to Rule 25-22.032, F.A.C, Customer Complaints, or Rule 25-22.036, F.A.C., Initiation of Formal Proceedings.

Rulemaking Authority 350.127(2), 366.05(1), 366.92 FS. Law Implemented 366.02(2), 366.04(2)(c), (5), (6), 366.041, 366.05(1), 366.81, 366.82(1), (2), 366.91(1), (2), 366.92 FS. History–New 2-11-02, Amended 4-7-08.

25-6.0131 Regulatory Assessment Fees; Investor-owned Electric Companies, Municipal Electric Utilities, Rural Electric Cooperatives.

(1) As applicable and as provided in Section 350.113, F.S., each company, utility, or cooperative shall remit to the Commission a fee based upon its gross operating revenue. This fee shall be referred to as a regulatory assessment fee. Regardless of the gross operating revenue of a company, a minimum annual regulatory assessment fee of $25 shall be imposed.

(a) Each investor-owned electric company shall pay a regulatory assessment fee in the amount of .00072 of gross operating revenues derived from intrastate business, excluding sales for resale between public utilities, municipal electric utilities, and rural electric cooperatives or any combination thereof.

(b) Each municipal electric utility and rural electric cooperative shall pay a regulatory assessment fee in the amount of 0.00015625 of its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities, municipal electric utilities, and rural cooperatives or any combination thereof.

(2) Regulatory assessment fees are due each January 30 for the preceding period or any part of the period from July 1 until December 31, and on July 30 for the preceding period or any part of the period from January 1 until June 30.

(3) If the due date falls on a Saturday, Sunday, or a holiday, the due date is extended to the next business day. If the fees are sent by registered mail, the date of the registration is the United States Postal Service's postmark date. If the fees are sent by certified mail and the receipt is postmarked by a postal employee, the date on the receipt is the United States Postal Service's postmark date. The postmarked certified mail receipt is evidence that the fees were delivered. Regulatory assessment fees are considered paid on the date they are postmarked by the United States Postal Service or received and logged in by the Commission's Division of Administrative Services Tallahassee. Fees are considered timely paid if properly addressed, with sufficient postage and postmarked no later than the due date.

(4) Commission Form PSC/ECR 68 (01/99), entitled "Investor-Owned Electric Utility Regulatory Assessment Fee Return"; Form PSC/ECR 69 (07/96), entitled "Municipal Electric Utility Regulatory Assessment Fee Return"; and Form PSC/ECR 70 (07/96), entitled "Rural Electric Cooperative Regulatory Assessment Fee Return" are incorporated into this rule by reference and may be obtained from the Commission's Division of Administrative Services. The failure of a utility to receive a return form shall not excuse the utility from its obligation to timely remit the regulatory assessment fees.

(5) Each company, utility, or cooperative shall have up to and including the due date in which to:

(a) Remit the total amount of its fee; or

(b) Remit an amount which the company, utility, or cooperative estimates is its full fee.

(6) Where the company, utility, or cooperative remits less than its full fee, the remainder of the full fee shall be due on or before the 30th day from the due date and shall, where the amount remitted was less than 90 percent of the total regulatory assessment fee, include interest as provided by paragraph (8)(b) of this rule.

(7) A company may request from the Division of Administrative Services a 30-day extension of its due date for payment of regulatory assessment fees or for filing its return form.

(a) The request for extension must be written and accompanied by a statement of good cause.

(b) The request for extension must be received by the Division of Administrative Services at least two weeks before the due date.

(c) Where a company, utility, or cooperative receives an extension of its due date pursuant to this rule, then the entity shall remit a charge in addition to the regulatory assessment fee, as set out in Section 350.113, F.S.

(8) The delinquency of any amount due to the Commission from the company, utility, or cooperative pursuant to the provisions of Section 350.113, F.S., and this rule, begins with the first calendar day after any date established as the due date either by operation of this rule or by an extension pursuant to this rule.

(a) A penalty, as set out in Section 350.113, F.S., shall apply to any such delinquent amounts.

(b) Interest at the rate of 12 percent per annum shall apply to any such delinquent amounts.

Specific Authority 350.127(2) FS. Law Implemented 350.113, 366.14 FS. History–New 5-18-83, Amended 2-9-84, Formerly 25-6.131, Amended 6-18-86, 10-16-86, 3-7-89, 2-19-92, 7-7-96, 1-1-99.

Tab 3

State Reports

Reporting Requirements for

Interconnection and Net Metering of Customer-Owned Renewable Generation (re: Section 25-6.065 (10) F.A.C.)

For year ending December 31, 2013

RGI - Renewable Generation Interconnections
GPR - Gross Power Rating (AC)

Type	Name of Utility	Date Filed	# Solar PV RGI	# Wind RGI	# Other RGI	Total # of RGI*	Solar GPR (kW)	Wind GPR (kW)	Other GPR (kW)	Total kW GPR (kW)	Total kWh rec'd. by cust. fm utility	Total kWh del. to the utility	Total pmt. made to cust. by utility
IOU	Florida Power & Light (FPL)	4/1/2014	2,562	11	1	2,565	22,632	94	750	23,476	371,051,442	10,500,816	$23,559.00
	Florida Public Utilites Company (FPU)	4/11/2014	52			52	238			238	644,348	101,377	$34.04
	Gulf Power Company (GPC)	4/1/2014	299	7		306	1,175	17		1,192	4,806,755	690,470	$1,293.36
	Duke Energy Florida, Inc. (DEF)	4/1/2014	1,480	3		1,483	13,149	4		13,153	665,807,390	5,601,865	$29,447.00
	Tampa Electric Company (TEC)	4/1/2014	425		1	426	6,682		50	6,732	175,355,214	1,691,584	$9,346.32
Total IOU			**4,818**	**21**	**2**	**4,832**	**43,876**	**115**	**800**	**44,791**	**1,217,665,149**	**18,586,112**	**$63,679.72**
Municipal	Alachua, City of (ALA)	4/1/2014	3			3	40			40	420,027	37,947	$0.00
	Bartow, City of (BAR)	3/17/2014	7	1		8	45	2		47	392,105	13,988	$0.00
	Beaches Energy Services (formery Jacksonville Bch)	3/31/2014	30			30	214			214	637,481	92,564	$11,146.00
	Blountstown, City of (BLT)	3/10/2014	0			0	0			0			$0.00
	Bushnell, City of (BUS)	3/31/2014	0			0	0			0			$0.00
	Chattahoochee, City of (CHA)	4/11/2014	0			0	0			0			$0.00
	Clewiston, City of (CLE)	3/31/2014	0			0	0			0			$0.00
	Fort Meade, City of (FMD)	3/31/2014	0			0	0			0			$0.00
	Fort Pierce Utilities Authority (FTP)	3/31/2014	7			7	21			21	51,912	12,205	$310.32
	Gainesville Regional Utilities (GRU)	3/25/2014	193			193	1,638			1,638	N/A	871,726	$104,710.00
	Green Cove Springs, City of (GCS)	3/31/2014	4			4	52			52	114,339	14,139	$492.00
	Havana, Town of (HAV)	3/31/2014	3			3	35			35	47,511	18,363	$0.00
	Homestead, City of (HST)	3/28/2014	1			1	18			18	113,140	0	$0.00
	JEA (formerly Jacksonville Electric Authority)	3/27/2014	151	1		151	787	3		790	7,230,281	448,455	$0.00
	Keys Energy Services (formerly Key West Utility Bd)	3/31/2014	31			31	215			215	515,859	103,974	$9,306.47
	Kissimmee Utility Authority (KUA)	3/31/2014	23			23	144			144	1,529,121	63,081	$2,021.57
	Lake Worth Utilities Authority (LWU)	3/19/2014	6			6	30			30	59,516	21,336	$2,384.21
	Lakeland, City of (LAK)	3/31/2014	99			99	345			345	1,036,146	283,324	$0.00
	Leesburg, City of (LEE)	3/31/2014	9			9	55			55	108,449	30,195	$1,033.63
	Moore Haven, City of (MHN)	3/27/2014	0			0	0			0			$0.00
	Mount Dora, City of (MTD)	3/11/2014	2			2	11			11	23,649	6,020	$689.00
	Newberry, City of (NEW)	3/31/2014	3			3	17			17	260,727	144	$0.00
	New Smyrna Beach, Utilites Commission of (NSB)	3/31/2014	20			20	83			83	168,719	56,487	$780.44
	Ocala Electric Utility (OEU)	3/31/2014	81			81	608			608	324,227	0	$0.00
	Orlando Utilities Commission (OUC)	4/1/2014	81			81	5,880			5,880	11,266,804	1,464,182	$14,042.58
	Quincy, City of (QUI)	4/11/2014	0			0	0			0			$0.00
	Reedy Creek Utilities (RCU)	3/24/2014	1			1	19			19	15,400	11,720	$475.00
	Starke, City of (STK)	3/31/2014	2			2	30			30	37,873	18,040	$571.47
	St. Cloud, City of (STC)	4/1/2014	29			29	186			186	2,922,546	70,532	$790.34
	Tallahassee, City of (TAL)	4/1/2014	198			198	1,142			1,142	10,766,053	233,262	$0.00
	Vero Beach, City of (VER)	3/14/2014	16			16	134			134	131,642	1,565	$186.00
	Wauchula, City of (WAU)	5/22/2014	0			0	0			0			$0.00
	Williston, City of (WIL)	4/14/2014	0			0	0			0			$0.00
	Winter Park, City of (WPK)	3/27/2014	7			7	38			38	117,653	26,472	$0.00
Total Municipal			**1,007**	**2**	**0**	**1,008**	**11,787**	**5**	**0**	**11,792**	**38,291,180**	**3,899,721**	**$148,939.03**

Type	Name of Utility	Date Filed	# Solar PV RGI	# Wind RGI	# Other RGI	Total # of RGI	Solar GPR (kW)	Wind GPR (kW)	Other GPR (kW)	Total kW GPR (kW)	Total kWh rec'd. by cust. fm utility	Total kWh del. to the utility	Total pmt. made to cust. by utility
Rural	Central Florida Electric Cooperative, Inc. (CFC)	2/5/2014	24		1	25	137		1000	1,137	4,550,614	238,859	$12,314.07
Electric	Choctawhatchee Electric Cooperative, Inc. (CHW)	3/31/2014	44			44	187			187	314,755	92,868	$6,527.38
Coop	Clay Electric Cooperative, Inc. (CEC)	1/15/2014	122			122	779			779	919,777	100,489	$2,843.84
	Escambia River Electric Cooperative, Inc. (ESC)	3/7/2014	8			8	47			47	87,555	25,662	$1,011.07
	Florida Keys Electric Cooperative, Inc. (FKE)	2/7/2014	34			34	187			187	716,279	117,110	$11,288.00
	Glades Electric Cooperative, Inc. (GEC)	5/27/2014	21			21	122			122	210,858	78,560	$665.08
	Gulf Coast Electric Cooperative, Inc. (GUC)	3/31/2014	7			7	73			73	59,193	55,896	$2,571.22
	Lee County Electric Cooperative, Inc. (LEC)	3/20/2014	150			150	695			695	1,883,321	317,682	$1,244.26
	Okefenoke Rural Electric Cooperative, Inc. (OKC)	3/12/2014	11			11	47			47	131,465	17,845	$58.82
	Peace River Electric Cooperative, Inc. (PRC)	3/12/2014	46			46	315			315	558,066	187,334	$2,885.67
	Sumter Electric Cooperative, Inc. (SMC)	3/3/2014	190	1		191	1,021	2		1,023	41,408,200	555,569	$60,230.18
	Suwannee Valley Electric Cooperative, Inc. (SVC)	3/4/2014	9		1	10	44		600	644	3,145,656	1,599,917	$5,945.50
	Talquin Electric Cooperative, Inc. (TRC)	1/22/2014	69			69	656			656	8,908,819	390,180	$38,411.27
	Tri-County Electric Cooperative, Inc. (TRC)	2/6/2014	10			10	62			62	110,887	27,727	$3,216.33
	West Florida Electric Cooperative, Inc. (WFC)	4/1/2014	9			9	37			37	66,596	27,189	$1,458.49
	Withlacoochee River Electric Cooperative, Inc.(WRC)	2/4/2014	99	1		100	456	5		461	N/A	11,684	N/A
Total Rural Electric Cooperative			**853**	**2**	**2**	**857**	**4,865**	**7**	**1600**	**6,472**	**63,072,041**	**3,844,571**	**$150,671.18**

Grand Totals as of December 31, 2013

Type of Utility		# Utilities w/ RGI	# RGI Solar	# RGI Wind	# RGI Digester	# RGI Total	Solar GPR - kW	Wind GPR - kW	Digester GPR - kW	Total GPR - kW	Total kWh rec'd. by cust. fm utility	Total kWh del. to the utility	Total pmt. made to cust. by utility
Total IOU		**5**	**4,818**	**21**	**2**	**4,832**	**43,876**	**115**	**800**	**44,791**	**1,217,665,149**	**18,586,112**	**$ 63,679.72**
Total Municipal		**25**	**1,007**	**2**	**0**	**1,008**	**11,787**	**5**	**0**	**11,792**	**38,291,180**	**3,899,721**	**$ 148,939.03**
Total Rural Electric Cooperative		**16**	**853**	**2**	**2**	**857**	**4,865**	**7**	**1,600**	**6,472**	**63,072,041**	**3,844,571**	**$ 150,671.18**
Grand Total		**46**	**6,678**	**25**	**4**	**6,697**	**60,528**	**127**	**2,400**	**63,055**	**1,319,028,370**	**26,330,404**	**$ 363,289.93**

*** For the calculation of Total # of RGI, customers of FPL, GPC, and JEA with both Solar PV and Wind units were counted as only one interconnection.**

Extract From March 3, 2015

Public Service Commission

Meeting Packet

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 27, 2015

TO: Braulio L. Baez, Executive Director

FROM: Walter Clemence, Public Utility Analyst II, Office of Industry Development and Market Analysis
David Dowds, Public Utilities Supervisor, Office of Industry Development and Market Analysis
Mark Futrell, Director, Office of Industry Development and Market Analysis

RE: Overview of Solar Energy in Florida

Critical Information: Please place on the March 3, 2015 Internal Affairs.
BRIEFING ONLY

This memorandum is to provide an informational overview of current and new solar deployments in Florida, cost trends for solar installations, and a discussion of customer-owned renewable generation and statistics on customer-owned installed capacity. No Commission action is requested.

Existing Solar Resources

Florida has 218 megawatts (MW) of installed solar capacity as of December 31, 2013. Florida utilities have installed approximately 117 MW of solar photovoltaic (PV) and solar thermal capacity in Florida. Utilities have contracted for an additional 39.5 MW of installed capacity, and customers have installed approximately 60.5 MW of distributed solar generation behind their meters.

Utility Owned			**Gross MW**
FPL	Desoto Next Gen Solar Energy Center	PV	25
FPL	Space Coast	PV	10
FPL	FPL Juno Beach Living Lab	PV	0.0970
FPL	Business PV for Schools	PV	0.1600
FPL	Martin Solar	Thermal	75.0
TECO	Museum of Science & Industry	PV	0.0182
TECO	Walker Middle School	PV	0.0034
TECO	Manatee Viewing Center	PV	0.0372
TECO	Middleton High School	PV	0.0089
TECO	Tampa's Lowry Park Zoo	PV	0.0128

TECO	Florida Aquarium	PV	0.0086
DEF	Econlockhatchee Photovoltaic Array	PV	0.0070
DEF	DEF owned Installations	PV	0.9230
FMPA	NOAA Eco-Discovery Center	PV	0.0300
GRU	Small Distributed Rooftop PV Panels	PV	0.0086
OUC	OUC Reliable Plaza PV System	PV	0.0320
TAL	Multiple Utility-owned installations	PV	0.2230
JEA	Multiple Utility-owned installations	PV	0.2220
LAK	Airport Phase 1	PV	2.3000
LAK	Airport Phase 2	PV	3.0000
LAK	Sun Edison - Civic Center	PV	0.2500
	Source: Ten Year Site Plan	Utility Owned	117.34

Existing Non-Utility Owned Generation			Gross MW
FPL	Rothenbach Park	PV	0.2500
FPL	First Solar	PV	0.2000
GRU	Multiple Aggregated Distributed Facilities	PV	18.6
OUC	Fleet Solar Project	PV	0.3350
OUC	Gardenia Solar Project	PV	0.2680
OUC	Stanton Solar Farm	PV	5.1
JEA	Jacksonville Solar	PV	15.0
	Source: Ten Year Site Plan	Non-Utility	39.73

Customer-Owned Solar Generation

In 2002 the Commission adopted Rule 25-6.065, Florida Administrative Code, to allow residential customers to interconnect customer-owned solar systems of up to 10 KW and provided that any excess energy generated by the customer's system would be purchased by the utility. In 2008, the FPSC approved a revised rule that applies to all customers and provides for an expedited interconnection process and allows for net metering of customer-owned renewable energy systems of up to 2 MW.

In 2008, the effective year of the revised rule, customer-owned renewable solar generation accounted for approximately 3 MW of renewable capacity. As of 2013, approximately 60.5 MW MW was customer-owned solar PV.

Customer-Owned Solar Generation												
	# of Customer-Owned Solar Systems						kW Gross Power Rating					
	2008	2009	2010	2011	2012	2013	2008	2009	2010	2011	2012	2013
IOU	383	1,045	1,855	2,803	3,799	4,818	1,696	7,653	12,442	19,441	30,401	43,876
Municipal	137	313	493	614	791	1,007	797	3,378	4,099	5,002	7,021	11,787
Rural Electric Cooperative	57	267	461	549	684	853	272	1,955	2,667	3,262	4,099	4,865
TOTAL	577	1,625	2,809	3,966	5,274	6,678	2,765	12,986	19,208	27,705	41,521	60,528

Proposed Solar Resources

The most recent Ten Year Site Plans showed that utilities planned to add 4.5 MW of solar PV during the 2014-2023 timeframe.

Planned Utility-Owned Generation			Gross MW
FPL	Business PV for Schools	PV	0.5000
FPL	CISP (Community Solar)	PV	3.8800
TECO	LEGOLAND	PV	0.0255
TAL	Multiple Installations	PV	0.1200
	Source: Ten Year Site Plan	Utility Owned	4.53

As part of the Ten Year Site Plan process, utilities also identified the as-available energy contracts that they plan to enter into within the 2014-2023 timeframe, as shown in the following chart.

Planned Non-Utility Generation			Gross MW
DEF	Blue Chip Energy Lake Mary	PV	10.00
DEF	Blue Chip Energy Sorrento	PV	40.00
DEF	National Solar Gadsden	PV	50.00
DEF	National Solar Hardee	PV	50.00
DEF	National Solar Suwannee	PV	50.00
DEF	National Solar Highlands	PV	50.00
DEF	National Solar Osceola	PV	50.00
TAL	TBD	PV	1.70
TAL	Innovation Park	PV	0.40
TAL	Yulee Street	PV	0.85

LAK	Sun Edison	PV	6.00
LAK	Sun Edison-Sutton	PV	6.00
LAK	Sun Edison-TBA	PV	7.50
LAK	Sun Edison-TBA	PV	5.00
	Source: Ten Year Site Plan	Non-utility	327.45

In addition to the aforementioned projects, staff highlights below a few projects that were announced subsequent to the release of the 2014 Ten Year Site Plans.

Florida Power and Light Company's Solar Projects

- On January 26, 2015, FPL announced its plans to construct three 74 MW solar photovoltaic facilities by the end of 2016, at three sites:
  - Citrus Solar Energy Center – DeSoto County, near FPL's existing 25 MW solar photovoltaic facility which opened in 2009.
  - Babcock Ranch Solar Energy Center – Charlotte County.
  - Manatee Solar Energy Center – Manatee County, on the site of FPL's Manatee generating facilities.
- According to FPL, the three sites have sufficient transmission and substation infrastructure in place.
- FPL has not announced plans for the recovery of costs associated with the proposed facilities.
- As shown in the utility's Ten Year Site Plan, the utility plans to add 3.88 MW of community solar in the 2014-2023 timeframe.
- On February 20, 2015, FPL announced its plans to construct a 1.7 MW grid-tied solar PV facility at Daytona International Speedway. Construction is to begin in the fall of 2015 with the goal that the system will be operational by the end of the year.

Florida Power and Light Company's Voluntary Solar Partnership Pilot Program[1]

- Offers customers an opportunity to voluntarily contribute $9.00 per month toward supply-side solar generation facilities owned by FPL in its service territory.
  - Available to all residential, commercial, and industrial customers.
- FPL will use the contributions to support the net revenue requirement of constructing and operating relatively small solar generating facilities.
- The electricity generated by the solar generation facilities will displace fuel that otherwise would have been used for generation, resulting in avoided fuel and emissions costs.
- The size of the solar projects will be determined based on the contributions received.
- Customers may enroll or cancel their enrollment at any time.

[1] See Order No. PSC-14-0468-TRF-EI, issued August 29, 2014 in Docket No. 140070-EI, In re: Petition for approval of voluntary solar partnership pilot program and tariff, by Florida Power & Light Company.

Tampa Electric Company - Tampa International Airport Project

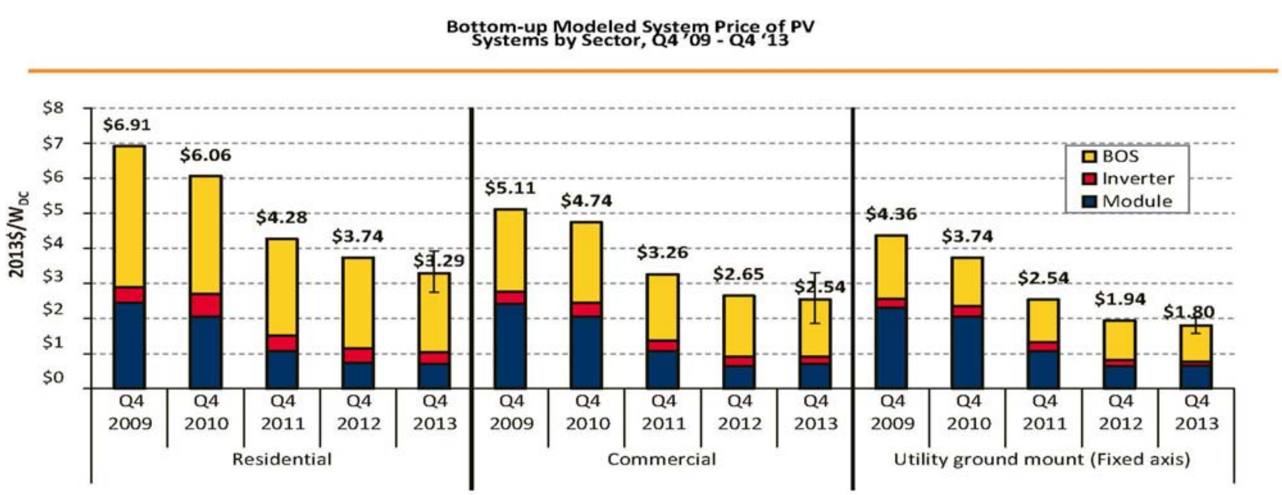
- On September 30, 2014, Tampa Electric Company (TECO) announced it will construct 2 MW of solar PV at the airport.
- The project is to be completed by the end of 2015.
- TECO will own the solar PV and will lease the airport garage roof on which the solar PV is to be located for $15,000/year.
- TECO will receive the 30% federal tax credit.
- Energy from the solar PV will be fed into TECO's grid and not be consumed directly by the airport.

Gulf Power Company's Solar Petition – Docket No. 150035-EI

- On January 22, 2015, Gulf Power Company filed for approval of three purchased power agreements totaling 120 MW for solar photovoltaic projects to be located at military installations:
  - Eglin Air Force Base, Okaloosa County – 30 MW
  - Holley Naval Landing Field, Santa Rosa County – 40 MW
  - Saufley Naval Landing Field, Escambia County – 50 MW
- A recommendation on the petition is currently scheduled for the April 16, 2015 Agenda Conference.

<u>**Cost Trends**</u>

The costs associated with the installation of solar PV have been steadily decreasing. The graph below shows that the declines have been seen in all three sectors -- residential, commercial, and utility scale installations. The graph shows that over the period 4th quarter 2009 – 4th quarter 2013, the bottom-up modeled system prices have declined by 52%, 50%, and 59% for residential, commercial, and utility scale installations, respectively.



Source: 2014 Edition of DOE's Photovoltaic System Pricing Trends

Information provided by the investor-owned electric utilities in the 2014 goal setting proceeding also recognized the declining cost of solar PV for residential and commercial installations. For example, Duke Energy's witness testified that the cost of solar PV for residential installations declined from \$5.01/watt_{dc} in 2011 to \$4.13/watt_{dc} in 2013. Similarly, the cost of solar PV for commercial installations declined from \$5.33/watt_{dc} in 2011 to \$3.89 in 2013. Gulf Power Company reported that the installed cost of solar PV systems (residential and commercial) dropped from an average of \$5.54/watt_{dc} in 2011 to \$3.42/watt_{dc} in 2014.

Demand Side Management Solar Pilot Programs

Section 366.82, F.S., directs the Commission to adopt appropriate goals for increasing the development of demand-side renewable energy systems. In developing goals, the Commission is to take into consideration the benefits and costs to the consumer participating in the measure and the benefits and costs to the general body of ratepayers. In the 2009 goal setting proceeding, the Commission found that solar measures, including solar PV and solar thermal, did not pass the cost-effectiveness tests required by Rule 25-17.008, F.A.C. However, the Commission ordered the investor-owned electric utilities (IOUs) to develop solar pilot programs in order to address the intent of the Legislature to place added emphasis on demand-side renewable resources.[2] The Commission established a spending cap for the IOUs of approximately \$24.5 million per year total in order to protect ratepayers from undue rate increases. The approved solar pilot programs provide customer rebates to offset a portion of the installation costs for solar photovoltaic and solar hot water heating systems, and also provide solar energy equipment to low-income customers and to schools. The following data provides information on program participation, costs, and installed solar PV capacity.

Solar Pilot Program Participation and Expenditures

The table below shows that during the period 2011-2013, a total of nearly \$50 million was expended for the solar pilot programs and 5,845 customers participated in the programs.

Solar Pilot Program Expenditures and Participation
2011-2013 (Includes both PV and Thermal)

	Expenditures	Participants
FPL	$29,853,514	3,962
DEF	$13,788,013	1,318
TECO	$3,793,723	325
GULF	$2,300,000	240
Total	$49,735,250	5,845

Source: 2014 conservation goals proceeding.

[2] See Order No. PSC-09-0855-FOF-EG, issued December 30, 2009, in Docket Nos. 080408-EG, 080409-EG, 080410-EG, 080412-EG, 080413-EG, In re: Commission Review of numeric Conservation Goals.

The following tables provide more detailed information on solar pilot program participation and expenditures during 2011-2013.

Florida Power and Light Company 2011-2013	Number of Participants	Total Expenditures	Average Expenditure/Participant
Solar Water Heating - Residential & Low Income New Construction	2968	$4,469,845	$1,506
Solar Water Heating - Business	38	629,408	16,563
Photovoltaic (PV) - Residential	774	11,045,895	14,271
Photovoltaic (PV) - Business	153	5,488,461	35,872
Photovoltaic (PV) - Business PV for Schools	29	4,057,967	139,930
Research & Demonstration	n/a	1,158,841	
Non-program Specific	n/a	3,003,097	
TOTAL	3962	$29,853,514	$7,535

Source: 2014 Energy Conservation Goals Proceeding.

Duke Energy Florida, Inc. 2011-2013	Number of Participants	Total Expenditures	Average Expenditure/Participant
Solar Water Heating Low Income	63	$321,874	$5,109
Solar Water Heating - Residential	847	587,132	693
Photovoltaic (PV) - Residential	346	5,522,911	15,962
Photovoltaic (PV) - Commercial	39	2,755,173	70,645
Photovoltaic (PV) for Schools	23	4,097,400	178,148
Research and Demonstration	n/a	504,523	
TOTAL	1318	$13,788,013	$10,461

Source: 2014 Energy Conservation Goals Proceeding.

Tampa Electric Company 2011-2013	Number of Participants	Total Expenditures	Average Expenditure/Participant
Photovoltaic (PV) - Residential	168		
Photovoltaic (PV) - Commercial	24		
PV Systems for Schools	3		
Solar Water Heating - Residential	120		
Solar Water Heating - Low Income	10		
Total	325	$3,793,723	$11,673

Source: 2014 Energy Conservation Goals Proceeding.

Gulf Power Company 2011-2013	Number of Participants	Total Expenditures	Average Expenditure/Participant
Photovoltaic (PV) - Residential & Commercial	132	$1,289,000	$9,765
PV Systems for Schools	2	209,000	104,500
Solar Water Heating - Residential	76	88,000	1,158
Solar Water Heating - Low Income	30	145,000	4,833
Administrative Expenses	n/a	569,000	
TOTAL	240	$2,300,000	$9,583

Source: 2014 Energy Conservation Goals Proceeding.

Solar Pilot Program Costs – Incentives & Other Expenses

The following tables provide data on program expenses divided between incentives and all other expenses. Incentives refer to the monetary rebates provided to qualifying customers who installed a solar PV or water heating system. Other expenses include payroll, marketing and other overhead.

Solar Pilot Program Costs 2011-2013

Duke Energy Florida, Inc.

Program	Other Expenses	% of Total	Incentives	% of Total	Total
Solar Water Heating with EM	$153,187	26.1%	$433,945	73.9%	$587,132
Research and Demonstration	$504,523	100.0%	$0	0.0%	$504,523
Solar Water Heating Low Income	$78,970	24.5%	$242,905	75.5%	$321,875
Photovoltaic for Schools Pilot	$161,299	3.8%	$4,133,050	96.2%	$4,294,349
Residential Solar Photovoltaic	$370,971	7.0%	$4,954,991	93.0%	$5,325,962
Commercial Solar Photovoltaic	$155,848	5.7%	$2,599,325	94.3%	$2,755,173
Total	$1,424,798	10.3%	$12,364,216	89.7%	$13,789,014

Florida Power and Light Company

Program	Other Expenses	% of Total	Incentives	% of Total	Total
Res. Solar H2O Heating Pilot	$796,850	22.5%	$2,752,000	77.5%	$3,548,850
Res. Solar H2O Heating (Low Inc.) Pilot	$131,990	14.3%	$789,005	85.7%	$920,995
Residential Photovoltaic Pilot	$415,216	3.8%	$10,630,678	96.2%	$11,045,894
Business Solar H2O Heating Pilot	$249,463	39.6%	$379,945	60.4%	$629,408
Business Photovoltaic Pilot	$317,603	5.8%	$5,170,859	94.2%	$5,488,462
Business Photovoltaic for Schools Pilot	$570,856	100.0%	$0	0.0%	$570,856
Renewable Research and Demo. Project	$1,158,841	100.0%	$0	0.0%	$1,158,841
Solar Pilot Projects Common Expenses	$2,075,160	100.0%	$0	0.0%	$2,075,160
Total	$5,715,979	22.5%	$19,722,487	77.5%	$25,438,466

Gulf Power Company

Program	Other Expenses	% of Total	Incentives	% of Total	Total
Renewable Energy Plan Common	$569,452	100.0%	$0	0.0%	$569,452
Solar for Schools	$139,906	100.0%	$0	0.0%	$139,906
Solar Thermal Water Heating	$12,187	13.8%	$76,000	86.2%	$88,187
Solar PV	$11,835	0.9%	$1,277,330	99.1%	$1,289,165
Solar Thermal Water Heating - Low Income	$0	0.0%	$144,776	100.0%	$144,776
Total	$733,380	32.9%	$1,498,106	67.1%	$2,231,486

Tampa Electric Company

Program	Other Expenses	% of Total	Incentives	% of Total	Total
Renewable Energy Systems Initiative	$598,495	15.8%	$3,195,228	84.2%	$3,793,723
Total	$598,495	15.8%	$3,195,228	84.2%	$3,793,723

Source: Energy Conservation Cost Recovery Clause Schedules.

Solar Photovoltaic Capacity Installed – 2011-2013

The table below provides the capacity of solar PV systems installed by customers. Duke Energy Florida, Inc. and Gulf Power Company reported that some customers installed solar PV systems with capacity in excess of the capacity provided by the maximum rebate. Data is provided for the incentivized capacity and the total capacity installed.

Solar PV Installed Capacity Funded by Solar Pilot Programs
kW DC Rating 2011-2013

Duke Energy Florida, Inc.	2011	2012	2013	Total
Residential Solar PV - Incentivized	557	733	1,205	2,495
Residential Solar PV - Total Installed	567	753	1,239	2,559
Commercial Solar PV - Incentivized	632	593	609	1,834
Commercial Solar PV - Total Installed	1,667	1,996	631	4,294
Solar for Schools - Incentivized	190	200	190	580
Solar for Schools - Total Installed	197	200	190	587
Total Incentivized	1,379	1,526	2,004	4,909
Total Installed	2,431	2,949	2,060	7,440

Florida Power and Light Company	2011	2012	2013	Total
Residential Solar PV	1,690	1,650	2,272	5,612
Business Solar PV	598	1,526	2,534	4,658
Solar for Schools	0	0	190	190
Total	2,288	3,176	4,996	10,460

Gulf Power Company	2011	2012	2013	Total
Solar PV - Incentivized	204	218	218	639
Solar PV - Total Installed	267	273	288	828
Solar for Schools	0	10	10	20
Total Incentivized	204	228	228	659
Total Installed	267	283	298	848

Tampa Electric Company	2011	2012	2013	Total
Residential Solar PV	311	495	479	1,285
Commercial Solar PV	74	61	90	225
Solar for Schools	10	10	10	30
Total	395	566	579	1,540

Source: FPSC staff data request.

2014 Goal Setting Proceeding - Cost-Effectiveness Analysis Results

As part of the 2014 goal setting proceeding, the Commission evaluated the cost-effectiveness of the Solar Pilot Programs, solar PV and solar hot water heating measures. The tables below provide the results of the cost-effectiveness tests required by Rule 25-17.008, F.A.C. The Commission found that the programs are not cost-effective and experience gained since the 2009 goals proceeding indicates that consumers have continued to install systems without any rebates. The Commission noted that the rebates associated with the solar pilot programs represent a large subsidy from the general body of ratepayers to a very small segment of each utility's customers.

Florida Power and Light Company Solar Pilot Programs	**Benefit Cost Ratio**		
	RIM	**TRC**	**Participant**
Solar Water Heating - Residential	0.51	0.18	0.50
Solar Water Heating - Low Income New Construction	0.21	0.28	1.52
Solar Water Heating - Business	0.34	0.19	0.58
Photovoltaic (PV) - Residential	0.46	0.27	0.74
Photovoltaic (PV) - Business	0.64	0.33	0.67
Photovoltaic (PV) - Business PV for Schools	0.13	0.15	1.19

Source: 2014 Energy Conservation Goals Proceeding

Duke Energy Florida, Inc. Solar Pilot Programs	**Benefit Cost Ratio**		
	RIM	**TRC**	**Participant**
Solar Water Heating for Low-income Residential	0.274	0.454	1.83
Solar Water Heating with Energy Management	0.596	0.580	0.79
Photovoltaic - Residential	0.376	0.547	1.23
Photovoltaic - Commercial	0.422	0.628	1.35
Photovoltaic for Schools	0.141	0.163	1.18

Source: 2014 Energy Conservation Goals Proceeding

Tampa Electric Company Solar Measures	**Benefit Cost Ratio**		
	RIM	**TRC**	**Participant**
Residential PV	0.38	0.41	1.20
Commercial PV	0.40	0.39	1.10
Residential Solar Water Heating	0.56	0.28	0.71

Source: 2014 Energy Conservation Goals Proceeding

Gulf Power Company Solar Measures	**Benefit Cost Ratio**		
	RIM	**TRC**	**Participant**
Solar PV (combined residential and commercial)	0.88	0.67	1.005 – 1.05
Solar Thermal Water Heating (Single Family)	0.74	0.56	0.98

Source: 2014 Energy Conservation Goals Proceeding

cc: Lisa Harvey, Charlie Beck

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: March 2, 2015

TO: Art Graham, Chairman

FROM: Walter Clemence, Public Utility Analyst II, Office of Industry Development and Market Analysis WC
David L. Dowds, Public Utilities Supervisor, Office of Industry Development and Market Analysis
Mark A. Futrell, Director, Office of Industry Development and Market Analysis MAF

RE: Solar Payback Information

The charts below are illustrative of what a customer in Florida may use for an economic analysis to determine the benefits of installing solar photovoltaic. The chart provides a simple payback calculation of installing an average system for both a residential and commercial customer.

Residential 5kW		
	w/Utility Rebate	No Utility Rebate
System Cost ($3290 kW)	$16,450	$16,450
Utility Rebate ($2/watt)	$10,000	$0
Federal Tax Credit (30%)	$1,935	$4,935
Total Cost	$4,515	$11,515
Approximate monthly kWh produced	657	657
Approximate monthly value of energy	$70	$70
Years to recover investment	5.35	13.65

Parties/Staff Handout
Internal Affairs/Agenda
on 03/03/2015
Item No. 1

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

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Parties/Staff Handout
Internal Affairs/Agenda
on 03/03/2015
Item No. 1

Commercial 200 kW		
	w/Utility Rebate	No Utility Rebate
System Cost ($2540 kW)	$508,000	$508,000
Utility Rebate (Max)	$50,000	$0
Federal Tax Credit (30%)	$137,400	$152,400
Total Cost	$320,600	$355,600
Approximate monthly kWh produced	26,280	26,280
Approximate monthly value of energy	$2,418	$2,418
Years to recover investment	11.05	12.26

The investment cost data used in the charts above are an approximation of the costs found in the 2014 Edition of DOE's Photovoltaic System Pricing Trends. The cost is based on a bottom-up modeled PV system. IOU solar pilot program rebates were approved by the Commission for 2011-2015.

The utility rebate assumes a rebate of $2.00/watt first 10kW, $1.50/Watt 10-25KW, $1.00/watt >25kW with a $50,000 maxium rebate.

The Federal Tax Credit is 30% of the actual cost of the system, applied net of any utility-provided rebate. The Federal Tax Credit for residential and commercial solar installations is available until December 31, 2016. After that time, the residential credit drops to zero and commercial credit drops to 10%.

The value of the energy produced assumes that all the energy is used on-site. This provides the greatest benefit for the consumer. The energy being used on-site offsets the consumer's need to purchase power from the utility. Therefore, it is valued at the retail cost of electricity.

The estimated monthly system kWhs produced assumes an 18% capacity factor. The approximate monthly value of energy is based on a retail electricity price (excluding taxes) of $0.107 per kWh for residential and $0.092 per kWh for commercial. The Years to recover investment is derived by dividing the net system cost by the monthly values of energy, then dividing the result by 12 to yield payback in years.

The charts above show that the inclusion of the utility rebates greatly reduces the amount of time necessary to recover the investment in the solar generation for a residential or commercial system. The inclusion of the utility rebate reduces the time to recover the investment from 13.65 years down to 5.35 for a residential installation. For a commercial installation the time to recover the investment is reduced from 12.26 years down to 11.05 years.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric conservation goals (Florida Power & Light Company).	DOCKET NO. 080407-EG
In re: Commission review of numeric conservation goals (Progress Energy Florida, Inc.).	DOCKET NO. 080408-EG
In re: Commission review of numeric conservation goals (Tampa Electric Company).	DOCKET NO. 080409-EG
In re: Commission review of numeric conservation goals (Gulf Power Company).	DOCKET NO. 080410-EG
In re: Commission review of numeric conservation goals (Florida Public Utilities Company).	DOCKET NO. 080411-EG
In re: Commission review of numeric conservation goals (Orlando Utilities Commission).	DOCKET NO. 080412-EG
In re: Commission review of numeric conservation goals (JEA).	DOCKET NO. 080413-EG ORDER NO. PSC-09-0855-FOF-EG ISSUED: December 30, 2009

The following Commissioners participated in the disposition of this matter:

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NANCY ARGENZIANO
NATHAN A. SKOP
DAVID E. KLEMENT

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FINAL ORDER APPROVING NUMERIC CONSERVATION GOALS

BY THE COMMISSION:

BACKGROUND

Sections 366.80 through 366.85, and 403.519, Florida Statutes (F.S.), are known collectively as the Florida Energy Efficiency and Conservation Act (FEECA). Section 366.82(2), F.S., requires us to adopt appropriate goals designed to increase the conservation of expensive resources, such as petroleum fuels, to reduce and control the growth rates of electric consumption and weather-sensitive peak demand. Pursuant to Section 366.82(6), F.S., we must review the conservation goals of each utility subject to FEECA at least every five years. The seven utilities subject to FEECA are Florida Power & Light Company (FPL), Progress Energy Florida, Inc. (PEF), Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Public Utilities Company (FPUC), Orlando Utilities Commission (OUC), and JEA (referred to collectively as the FEECA utilities). Goals were last established for the FEECA utilities in August 2004 (Docket Nos. 040029-EG through 040035-EG). Therefore, new goals must be established by January 2010.

In preparation for the new goals proceeding, we conducted a series of workshops exploring energy conservation initiatives and the requirements of the FEECA statutes. The first workshop, held on November 29, 2007, explored how we could encourage additional energy conservation. A second workshop held on April 25, 2008, examined how the costs and benefits of utility-sponsored energy conservation or demand-side management (DSM) programs, that target end-use customers, should be evaluated.

In 2008, the Legislature amended Section 366.82, F.S., such that when goals are established, we are required to: (1) evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems, (2) establish goals to encourage the development of demand-side renewable energy systems, and (3) allow efficiency investments across generation, transmission, and distribution as well as efficiencies within the user base. The Legislature also authorized us to allow an investor-owned electric utility (IOU) an additional return on equity of up to 50 basis points for exceeding 20 percent of their annual load-growth through energy efficiency and conservation measures and may authorize financial penalties for those utilities that fail to meet their goals. The additional return on equity shall be established by this Commission through a limited proceeding. Finally, the amendments to Section 366.82, F.S., provided funds for this Commission to obtain professional consulting services if needed. These statutes are implemented by Rules 25-17.001 through 25-17.0015, Florida Administrative Code (F.A.C.).

We held a third workshop on June 4, 2008, focused on appropriate methodologies for collecting information for a technical potential study. On June 26, 2008, seven dockets (080407-EG through 080413-EG) were established and represent the fourth time that we will set numeric conservation goals for each of the FEECA utilities. On November 3, 2008, we held a fourth workshop on the development of demand-side and supply-side conservation goals, including demand-side renewable energy systems. The results of the Technical Potential Study, conducted by the consulting firm ITRON on behalf of the seven FEECA utilities were presented at a fifth Commission workshop held on December 15, 2008.

On November 13, 2008, our staff contracted with GDS Associates, Inc. (GDS) to provide independent technical consulting and expert witness services during the conservation goal-setting proceeding. GDS is a multi-service engineering and management consulting firm, headquartered in Marietta, Georgia, with offices in Alabama, Texas, Maine, New Hampshire, Wisconsin, and Virginia. The firm has a broad array of management, strategic, and programmatic consulting expertise and specializes in energy, energy efficiency, water and utility planning issues. GDS was retained to review and critique the overall goals proposed by each utility, provide expert testimony and recommendations on alternative goals, where warranted. As an independent consultant, GDS was neither a separate party nor a representative of the staff. As such, GDS did not file post-hearing position statements or briefs.

By Order No. PSC-08-0816-PCO-EG, issued December 18, 2008, these dockets were consolidated for purposes of hearing and controlling dates were established. By Order No. PSC-09-0152-PCO, issued March 12, 2009, the controlling dates were revised, requiring the utilities to file direct testimony and exhibits on June 1, 2009. FPUC requested, and was granted, an extension of time to file its direct testimony on June 4, 2009.

The Natural Resources Defense Council and the Southern Alliance for Clean Energy (NRDC/SACE) were granted leave to intervene by the Commission on January 9, 2009.[1] The Florida Solar Coalition (FSC) was granted leave to intervene on January 27, 2009.[2] We acknowledged the intervention of the Florida Energy and Climate Commission (FECC) on March 11, 2009.[3] The Florida Industrial Power Users Group (FIPUG) was granted leave to intervene on July 15, 2009.[4]

An evidentiary hearing was held on August 10 - 13, 2009. We have jurisdiction over this matter pursuant to Sections 366.80 through 366.82, F.S.

On August 28, 2009, the FECC filed post-hearing comments in the proceeding. While the FECC took no position on any issues, the FECC concluded in its post-hearing comments that:

> The PSC should approve a level of goals for each utility that satisfies the utility's resource needs and results in reasonably achievable lower rates for all electric customers. As called for in the recent legislation, the PSC should also take into account environmental compliance costs that are almost a certainty over this goals-planning horizon. In this regard, the FECC supports a reasonably achievable level of DSM Goals based on measures that pass the E-RIM and Participants Tests to achieve the least-cost strategy for the general body of ratepayers. Additionally, the FECC believes that coupling cost-effective measures that satisfy E-RIM with solar measures that do not satisfy E-RIM will increase the customer take rate of solar applications at the lowest possible cost.

TECHNICAL POTENTIAL STUDY

For the current goal setting proceeding, the seven FEECA utilities invited NRDC/SACE to form a Collaborative to conduct an assessment of the technical potential for energy and peak demand savings from energy efficiency, demand response, and customer-scale renewable energy in their service territories.[5] The Collaborative then developed a request for proposal to conduct the study. The proposals were evaluated and the ITRON team was selected by the Collaborative to conduct the Technical Potential Study.[6]

FPL contended that the Technical Potential Study employed an iterative process that began with a list of measures that were provided within its original request for proposal (RFP).

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[1] Order No. PSC-09-0027-PCO-EG, issued January 9, 2009 (NRDC/SACE).
[2] Order No. PSC-09-0062-PCO-EG, issued January 27, 2009 (FSC).
[3] Order No. PSC-09-0150-PCO-EG, issued March 11, 2009 (FECC).
[4] Order No. PSC-09-0500-PCO-EG, issued July 15, 2009 (FIPUG).
[5] Technical Potential for Electric Energy and Peak Demand Savings in Florida, Final Report, pp. 1-1.
[6] Technical Potential for Electric Energy and Peak Demand Savings in Florida, Final Report, pp. 1-1 – 1-2.

PEF stated that the study focuses on measures that will work in Florida, have the greatest potential impact, and have a realistic possibility for adoption. TECO argued that using the collaborative process allowed each member to draw upon the collective judgment of the group, which would insure the ultimate proposals were the product of a rigorous and orderly process. Gulf asserted that NRDC/SACE were able to submit additional measures to be considered for analysis in the technical potential. FPUC argued that the study provides an adequate assessment of the technical potential. JEA/OUC argued that the study used measures and assessment techniques that were fully vetted through the collaborative process. The FEECA utilities contended that the study commissioned by the Collaborative satisfies Section 366.82(3), F.S.

NRDC/SACE argued that the study did not provide an adequate assessment of the technical potential. NRDC/SACE stated that the technical potential does not consider the full technical potential of all available demand- and supply-side efficiency measures. FSC argued that ranking measure savings by the use of "stacking" by the Collaborative is incorrect. FSC also criticized the study for omitting solar hybrid systems. FIPUG's brief and the comments filed by the FECC did not specifically address the Technical Potential Study.

Analysis

Witness Rufo, Director in the Consulting and Analysis Group at ITRON, stated that the technical potential is a theoretical construct that represents an upper limit of energy efficiency. Technical potential is what is technically feasible, regardless of cost, customer acceptance, or normal replacement schedules. The Technical Potential Study was conducted for each FEECA utility and then combined to create a statewide technical potential.

According to the testimony of witness Rufo, the Collaborative's first step was to identify and select the energy efficiency, demand response, and solar photovoltaic (PV) measures to be analyzed. The energy efficiency measures were developed with the FEECA utilities, ITRON, and NRDC/SACE, all proposing measures. Once a master list was developed, ITRON conducted assessments of data availability and measure specific modeling issues. Demand response measures were identified using a combination of literature reviews of current programs and discussions within the Collaborative. The PV measures were identified by explicitly considering six characteristics specific to PV electrical systems. The six characteristics are: (1) PV material type, (2) energy storage, (3) tracking versus fixed, (4) array mounting design, (5) host sites, and (6) on- versus off-grid systems.

The ITRON assessment of the full technical potential included 257 unique energy efficiency measures, seven demand response programs, and three unique PV measures. Included in the energy efficiency list were 61 residential measures, 78 commercial measures, and 118 industrial measures. The demand response list included five residential, and two commercial/industrial measures. The PV list included one residential (roof top application) and two commercial measures (one rooftop application and one parking lot application).

Some of the 257 measures, such as Seasonal Energy Efficiency Ratio (SEER) 19 central air conditioners, hybrid desiccant-direct expansion cooling systems, and heat pump water heaters are likely to face supply constraints in the near future. The energy efficiency list also includes some end-use specific renewable measures, e.g., solar water heating and PV-powered pool pumps. While some measures may have obstacles to overcome regarding customer acceptance, it is appropriate to include them in the technical potential.

The table below shows the results of the Statewide Technical Potential Study. Baseline energy is the total electricity sales for the FEECA utilities in 2007.[7]

Sector	Annual Energy			Summer System Peak			Winter System Peak		
	Base line (2007)	Technical Potential		Base line (2007)	Technical Potential		Base line (2007)	Technical Potential	
	(GWh)	(GWh)	(%)	(MW)	(MW)	(%)	(MW)	(MW)	(%)
Residential	94,745	36,584	38.6%	22,263	10,032	45.1%	22,728	6,461	28.4%
Commercial	65,051	19,924	30.6%	9,840	4,079	41.5%	7,490	2,206	29.5%
Industrial	11,877	2,108	17.7%	1,721	265	12.8%	1,289	217	17.5%
Total	171,672	58,616	34.1%	33,825	14,375	42.5%	31,508	8,883	28.2%

None of the parties offered any alternatives that were Florida-specific. They only showed that other states showed greater potential. They were unable to show how savings in other states could be achieved in Florida. Witness Rufo testified that criticisms of the ITRON data and modeling methods by NRDC/SACE and the staff witness are either without merit, inaccurate, or insignificant. Witness Rufo further testified that the baseline and measure data used in the Technical Potential Study reflect the best available data given the time and resources available.

The FEECA utilities did not develop supply-side conservation or efficiency measures to the same degree that they did demand-side measures. Generating utilities made note of their ongoing or planned efficiency and savings projects, but did not subject supply-side measures to the same analysis, nor did they develop the extensive lists of measures, that were examined by ITRON for demand-side savings. Supply-side measures require substantially different analytical methods than do demand-side systems and provide results that are difficult to combine with conservation goals. Supply-side efficiencies and conservation, rendered properly, would result either in less fuel being required or less loss along the transmission and distribution network. The Commission routinely addresses opportunities for supply-side efficiency improvements in our review of Ten-Year Site Plans. Therefore, such measures are better addressed separately from demand-side measures where their options can be better explored.

[7] Technical Potential for Electric Energy and Peak Demand Savings in Florida, Final Report, pp. 3-14.

Conclusion

Based on the record, we find that the Collaborative provided an adequate assessment of the technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems, pursuant to Section 366.82(3), F.S.

ACHIEVABLE POTENTIAL

Each of the FEECA utilities agreed that an adequate assessment of achievable potential was provided. The FEECA utilities that addressed the supply-side options, likewise, agreed that it was better addressed through a separate proceeding.

FSC, in its post-hearing brief, found the assessment insufficient for the five IOUs. FSC took no position on the municipal utilities. FSC's objection in the case of the IOUs mainly related to problems it had with the cost-effectiveness testing used in the process, which is further addressed below. NRDC/SACE, in its post-hearing brief, argued that the achievable potential was insufficient across the board and cited opposition to the cost-effectiveness testing.

Following the development of the DSM technical potential, previously discussed, three steps were used to develop the achievable potential: initial cost-effectiveness screening, determination of incentive levels, and development of achievable potential for six separate scenarios. Discussion of each step follows. FPUC, JEA, and OUC did not use this process and are discussed separately.

Initial Cost-Effectiveness Screening

During this phase of the process, the four generating IOUs (FPL, PEF, TECO, and Gulf) applied three cost-effectiveness tests to each measure: Enhanced Rate Impact Measure Test (E-RIM), Enhanced Total Resource Cost Test (E-TRC), and the Participants Test. None of the three tests included incentives that could be provided to participating customers. During this phase of the testing, the utilities also identified measures that had a payback period of less than two years in order to identify the free riders. Rule 25-17.0021(3), F.A.C., reads, in part:

> Each utility's projection shall reflect consideration of overlapping measures, rebound effects, free riders, interactions with building codes and appliance efficiency standards, and the utility's latest monitoring and evaluation of conservation programs and measures.

In order to meet the requirements of this Rule, the four generating IOUs removed certain measures because of participant "payback" periods of less than two years. Savings realized from such measures exceeded their costs within two years, according to utility analysis. These savings result from reduced kWh usage and, resultantly, a lower bill. The costs of such measures are up-front capital costs, where they exist, of installing or beginning the measure. Measures must both pass the Participants Test and have a payback of two years or less without any incentives to be removed during this step. We initially recognized a two-year payback period to address the free-ridership issue following the 1994 conservation goals hearing. By Order No. PSC-94-1313-FOF-EG,[8] we initially recognized FPL's use of the two-year payback period, and it has been used consistently ever since.

The two-year payback period was agreed to by the Collaborative as a means of addressing the free-ridership issue. In his testimony, FPL witness Dean described the rationale for the two-year period. He noted that estimates of the annual return on investment required to spur purchase of energy efficiency measures range from approximately 26 percent, which represents a payback period of just under four years, to over 100 percent, which represents a payback period less than a year. He further noted that most studies place the annual return on investment necessary to incent purchase in the 40 to 60 percent range. A 50 percent figure, which represents a payback of exactly two years, is squarely in the middle of that range.

The two-year payback criterion identified a substantial amount of energy savings from demand-side measures. For an illustrative example, the following chart demonstrates the amount of energy savings that could potentially be achieved from such measures:

Utility	(A) Maximum Achievable E-TRC (GWh)*	(B) E-TRC + 2-year payback measures (GWh)*	(C) Amount excluded due to 2-year screen (GWh) (B-A)	(D) Percent excluded due to 2-year screen (C/B)
FPL	2177.0	12066.9	9889.9	82.0%
PEF	1584.5	4689.8	3105.3	66.2%
TECO	310.3	1939.9	1629.6	84.0%
Gulf	251.4	1279.9	1028.5	80.4%
JEA	138.5	1070.7	932.2	87.1%
OUC	78.8	511.2	432.4	84.6%
FPUC	12.9	59.2	46.3	78.2%
Total	4553.4	21617.6	17064.2	78.9%

Even though the utilities did not include such measures in their proposed goals, customers are still free to adopt such measures and realize the resultant financial savings the measures represent. We are concerned that the utilities' use of the two-year payback criteria had the effect of screening out a substantial amount of potential savings. In order to recognize this potential, we have included in the residential goals for FPL, PEF, Gulf and TECO, savings from

[8] Order No. PSC-94-1313-FOF-EG, issued October 25, 1994, Docket No. 93-0548-EG, In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by Florida Power and Light Company; Docket No. 93-0549-EG, In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by Florida Power Corporation; Docket No. 93-0550-EG, In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by Gulf Power Company; Docket No. 93-0551-EG, In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by Tampa Electric Company.

the residential measures included in the top-ten energy savings measures that were screened-out by the two-year payback criterion.

Incentive Levels

The second step in the process for the four generating IOUs was to establish proper incentive levels. As a result, incentive levels for measures that did not pass the Participants Test during the initial cost-effectiveness screening (without incentives) were adjusted until the measures passed. Following this action, the E-RIM and E-TRC tests were re-run using costs that included the resulting incentive. Some measures that could not pass the Participants Test cost-effectiveness screening without incentives were removed from the achievable potential at this stage. Because measures were required to pass the Participants Test as well as E-RIM or E-TRC, incentives added to measures to allow them to be cost-effective for customers rendered some measures no longer cost-effective under either the E-RIM or E-TRC tests.

Scenario Analysis

In the third step of the process, the four generating IOUs analyzed measures that passed cost-effectiveness screening with incentives, in order to develop six scenarios for achievable potential. These utilities developed low, mid, and high incentive scenarios for both E-RIM and E-TRC. From these six scenarios, the achievable potential was developed. This achievable potential formed the basis of the goals proposed by the utilities in the next step of the overall process.

Other FEECA Utilities

FPUC, OUC, and JEA allowed ITRON to develop the achievable potential for them. ITRON followed a similar process in developing the achievable potential for the three small utilities that was followed for the generating IOUs in making their calculations. In each of these three cases, ITRON found no DSM measures that passed the E-RIM Test. As a result, the achievable potential for each of these three utilities was zero in all categories. These utilities are all smaller than the generating IOUs. Because of fewer customers, administrative costs and program development tend to render measures less cost-effective than they are for the generating IOUs.

Demand-Side Renewable Energy Systems

The Collaborative analyzed a small range of renewable energy systems in their analysis of achievable potential.[9] These measures were confined to geothermal heat pumps, solar water heaters, and small photovoltaic (PV) systems. These renewable energy systems were subjected to the same range of cost-effectiveness testing as the DSM measures discussed above. The generating IOUs found that some geothermal heat pumps did pass the cost-effectiveness tests

[9] Technical Potential for Electric Energy and Peak Demand Savings in Florida, Final Report, pp. A1 – A27.

and were included in the achievable potential. PEF also included some solar thermal measures in its achievable potential. No FEECA utility found that Solar PV measures passed the economic screening and thus should not be included in the achievable potential. Renewable energy systems were subject to the same analysis as conventional energy efficiency measures and either were incorporated into or excluded from achievable potential by the same standards.[10]

Conclusion

Each of the FEECA utilities, with the aid of ITRON, performed an adequate analysis of the demand-side conservation and efficiency measures, including demand-side renewable energy systems. The FEECA utilities did not provide an analysis of supply-side measures. We agree, however, that the methods appropriate to analyze demand-side measures are not well-suited to weighing supply-side measures. As a result, supply-side measures are best addressed in a separate proceeding.

REQUIRED COST-EFFECTIVENESS TESTS

Recent amendments to Section 366.82, F.S., provide greater specificity as to what we must consider when establishing conservation goals. The recent amendments, in relevant part, are as follows:

> (3) In developing the goals, the commission shall evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems. In establishing the goals, the commission shall take into consideration:
>
> (a) The costs and benefits to customers participating in the measure.
>
> (b) The costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions.

Appropriate Test for Section 366.82(3)(a), F.S.

All parties, except FSC, agreed that the Participants Test captures all of the relevant costs and benefits for customers who elect to participate in a DSM measure. The parties further agreed that the requirements of Section 366.82(3)(a), F.S., are reflected in the proposed goals because all included measures pass the Participants Test.

FSC argued that the goals proposed by FPL, PEF, TECO, Gulf, and FPUC do not adequately reflect the costs and benefits to customers participating in the measures pursuant to Section 366.82(3)(a), F.S. FSC appears to take issue with the techniques employed by the IOUs in calculating the energy savings and incentives for solar measures and argued that these flawed calculations cause solar measures to fail the Participants Test. In its analysis, FSC explained

[10] Technical Potential for Electric Energy and Peak Demand Savings in Florida, Final Report, pp. ES5 – ES 6.

how the impact of "stacking" increases the necessary incentive and lowers the energy savings attributed to solar technologies, thereby increasing the likelihood that these measures will fail the Participants Test. FSC took no position regarding OUC and JEA.

Section 366.82(3)(a), F.S., requires that we take into consideration the costs and benefits to customers participating in any measure to be included in a utility's DSM program. In addition, Rule 25-17.008, F.A.C., incorporates our Cost Effectiveness Manual.[11] The Cost Effectiveness Manual requires the application of the Participants Test in order to determine the cost-effectiveness of conservation programs by measuring the impact of the program on the participating customers. The customers' benefits of participation in programs may include bill reductions, incentives, and tax credits. Customer's costs may include bill increases, equipment and materials, and operations and maintenance.

Although FSC expressed its opinion that the inputs to the Participants Test are flawed, it agreed with the application of this test in general, along with the E-TRC Test. However, FSC offered no alternative inputs for the investor-owned utilities, nor did it provide any alternative to the results obtained from the application of the Participants Test. The FSC questioned ITRON on its use of "stacking" in the Technical Potential Study. Stacking is a means to understand the interaction between available measures to make sure that savings are not double counted. Witness Rufo testified that the use of "stacking" is an accepted practice to eliminate double counting that could occur if the measures were not stacked. We believe that "stacking" is useful and justified as it is a means to ensure that the savings from a program are not counted if those savings would be offset by the savings in a different measure.

We find that the Participants Test, as used by the utilities in this proceeding, satisfies the requirements of Section 366.82(3)(a), F.S. As described in Rule 25-17.008, F.A.C., the Participants Test measures the impact of the program on the participating customers. Based on the evidence in the record, as well as existing Commission Rules, we find that the Participants Test must be considered when establishing conservation goals in order to satisfy Section 366.82(3)(a), F.S.

Appropriate Test for Section 366.82(3)(b), F.S.

The FEECA utilities agreed that Section 366.82, F.S., does not specify or require a single cost-effectiveness test, but that a combination of two tests is sufficient to meet the requirements, specifically the RIM and Participants Tests. The TRC Test is considered by the utilities to be insufficient to meet the statute, and goals based upon it would have an upward pressure on rates. They also agreed that their analysis was comprehensive, including effects from a variety of sources, such as building codes, overlapping measures, appliance standards, and other sources. Four of the seven FEECA utilities filed "enhanced" versions of the RIM and TRC tests, referenced as E-RIM and E-TRC. These tests included benefits from avoided carbon compliance costs.

[11] Florida Public Service Commission Cost Effectiveness Manual for Demand Side Management Programs and Self-Service Wheeling Proposals, effective July 17, 1991.

NRDC/SACE asserted that the language found in Section 366.82(3)(b), F.S., clearly describes the TRC Test. NRDC/SACE argued that the TRC Test is the cost-effectiveness test that focuses on the "general body of ratepayers as a whole." NRDC/SACE further elaborated that the TRC Test, unlike the RIM Test, includes both "utility incentives and participant contributions." In addition, a flaw in the calculation of benefits is the denial of value for reduced demand until the in-service date of the avoided unit. Also, the possibility of avoiding units that are already approved but have not yet finished construction should be considered. Finally, NRDC/SACE contended that administrative costs allocated to measures were unreasonable and caused an inappropriate reduction of the goals.

FIPUG suggested that we primarily consider the final impact on customers, and that any goals should not present an undue rate impact upon customers. FIPUG contended that we should continue to give significant weight to the RIM Test. FIPUG asserted, however, that the test should be performed consistently and uniformly between utilities.

FSC asserted that the analysis by the investor-owned utilities was insufficient, and that the reduction of savings associated with solar measures was reduced by inappropriately stacking measures. FSC supported the E-TRC and Participants Tests, and further suggested that measures should be considered in combination or on a portfolio basis.

Section 366.82(3)(b), F.S., requires this Commission to consider "[t]he costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions." Both the RIM and TRC Tests address costs and benefits beyond those associated solely with the program participant. Four of the seven FEECA utilities filed "enhanced" versions of the RIM and TRC tests, referenced as E-RIM and E-TRC. These tests are identical to the RIM and TRC tests but include an estimate of avoided carbon compliance costs. As such, E-RIM and E-TRC portfolios will have greater savings than RIM or TRC portfolios respectively.

Rule 25-17.008, F.A.C., and the Cost Effectiveness Manual were adopted as part of the implementation of Section 366.82, F.S., prior to the recent amendments. Rule 25-17.008(3), F.A.C., directs us to evaluate the cost-effectivness of conservation measures and programs utilizing the following three tests: (1) the Participants Test, (2) the Total Resource Cost Test (TRC), and (3) the Rate Impact Measure Test (RIM). Rule 25-17.008(4), F.A.C., allows a party to provide additional data for cost-effectiveness reporting, such as the E-RIM and E-TRC tests. The figure below provides an illustration of the costs and benefits evaluated under each test.

Summary of Cost Effectiveness Test Components

	Participant	Total Resource Cost	Rate Impact Measure
Benefits	Bill Savings	Avoided Generation	Avoided Generation
	Incentives	Avoided Distribution	Avoided Distribution
	Tax Credits	Net System Fuel	Net System Fuel
Costs	Measure Cost	Equipment	Equipment
		Administrative	Administrative
		Measure Cost	Incentives
			Lost Revenues

It should first be noted that the RIM and TRC tests both consider benefits associated with avoiding supply side generation, i.e., construction of power plants, transmission, and distribution. The RIM and TRC tests also consider costs associated with additional supplies and costs associated with the utilities cost to offer the program. While some similarities exist between the two tests, it is the differences that are significant in determining which one, if not both, complies with Section 366.82(3)(b), F.S., and should be used to establish goals. The table below focuses on the differences in costs between the two tests.

Difference Between RIM and TRC Tests

	Total Resource Cost	Rate Impact Measure
Costs	Measure Cost	Incentives
		Lost Revenues

As illustrated above, the RIM Test considers utility offered incentives which are specifically required in Section 366.82(3)(b), F.S. Utility offered incentives are recovered through the Energy Conservation Cost Recovery clause and are a cost borne by all ratepayers. Therefore, a customer participating in a program, which is incentivized by the utility, receives a benefit; however, the incentive paid by the utility results in a cost to the general body of ratepayers. The TRC Test does not consider costs associated with utility incentives.

The TRC Test, as described in Rule 25-17.008, F.A.C., measures the net costs of a conservation program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The consideration of costs incurred by the participant is specifically required by Section 366.82(3)(b), F.S. Because the TRC Test excludes lost revenues, a measure that is cost-effective under the TRC Test would be less revenue intensive than a utility's next planned supply-side resource addition. However, the rate impact may be greater due to the reduced sales.

When establishing conservation goals, Section 366.82(3)(d), F.S., requires us to consider the costs imposed by state and federal regulations on the emission of greenhouse gases. The statute does not define "greenhouse gases," nor requires us to consider projected costs that may be imposed. However, in considering this requirement, the utilities viewed CO_2 as one of the generally accepted greenhouse gases close to being regulated. Other regulated gases, such as sulfur dioxide (SOx) and nitrous oxides (NOx), are already regulated by federal statute and the costs are included in the standard RIM and TRC tests. Each utility's calculation of a measures' cost-effectiveness employed modified versions of the RIM and the TRC tests that added a cost impact of CO_2 to the calculations. The revised tests are referred to as the E-RIM and E-TRC Tests. The utilities used different sources to establish the cost of CO_2 emissions, thereby employing different values in their cost-effectiveness testing. Therefore, FPL's goals could not be determined using TECO's estimated CO_2 costs.

Conclusion

While all parties agreed that the Participants Test is required by Section 366.82(3)(a), F.S., the same consensus does not exist when determining the appropriate test or tests for Section 366.82(3)(b) and (d), F.S. The seven FEECA utilities believe that the E-RIM Test satisfies the requirements of the statute while NRDC/SACE and FSC believe the E-TRC Test satisfies the requirements. We would note that the language added in 2008did not explicitly identify a particular test that must be used to set goals. Based on the analysis above, we find that consideration of both the RIM and TRC tests is necessary to fulfill the requirements of Section 366.82(3)(b), F.S. Both the RIM and the TRC Tests address costs and benefits beyond those associated solely with the program participant. By having RIM and TRC results, we can evaluate the most cost-effective way to balance the goals of deferring capacity and capturing energy savings while minimizing rate impacts to all customers. The "enhanced" versions of the RIM and TRC tests, referenced as E-RIM and E-TRC, are identical to the RIM and TRC tests, but include an estimate of avoided carbon compliance costs. As such, E-RIM and E-TRC portfolios will have greater savings than RIM or TRC portfolios respectively.

COMMISSION APPROVED GOALS

The goals proposed by each utility rely upon the E-RIM Test. Our intention is to approve conservation goals for each utility that are more robust than what each utility proposed. Therefore, we approve goals based on the unconstrained E-TRC Test for FPL, PEF, TECO, Gulf, and FPUC. The unconstrained E-TRC test is cost effective, from a system basis, and does not limit the amount of energy efficiency based on resource reliability needs. The E-TRC test includes cost estimates for future greenhouse gas emissions, but does not include utility lost revenues or customer incentive payments. As such, the E-TRC values are higher than the utility proposed E-RIM values. In addition, we have included the saving estimates for the residential portion of the top ten measures that were shown to have a payback period of two years or less in the numeric goals for FPL, PEF, TECO, and Gulf. When submitting their programs for our approval, the utilities can consider the residential portion of the top ten measures, but they shall not be limited to those specific measures.

OUC and JEA proposed goals of zero, yet committed to continue their current DSM program offerings. We are setting goals for OUC and JEA based on their current programs so as not to unduly increase rates. The annual numeric goals for each utility are shown below:

Commission-Approved Conservation Goals for FPL

	Residential								
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	25.2	42.5	67.7	20.9	12.3	33.2	29.1	90.5	119.6
2011	37.2	42.5	79.7	30.1	12.3	42.4	55.3	90.5	145.8
2012	47.7	42.5	90.2	38.0	12.3	50.3	78.3	90.5	168.8
2013	56.0	42.5	98.5	44.0	12.3	56.3	96.2	90.5	186.7
2014	61.8	42.5	104.3	47.9	12.3	60.2	109.5	90.5	200.0
2015	58.2	42.5	100.7	43.6	12.3	55.9	102.5	90.5	193.0
2016	53.4	42.5	95.9	39.0	12.3	51.3	92.9	90.5	183.4
2017	48.9	42.5	91.4	34.7	12.3	47.0	83.7	90.5	174.2
2018	44.9	42.5	87.4	30.9	12.3	43.2	75.9	90.5	166.4
2019	40.8	42.5	83.3	27.1	12.3	39.4	67.0	90.5	157.5
Total	474.0	425.0	899.0	356.0	123.0	479.0	790.3	905.0	1,695.3

	Commercial/Industrial								
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	42.7	0.0	42.7	8.1	0.0	8.1	84.7	0.0	84.7
2011	62.5	0.0	62.5	9.9	0.0	9.9	149.4	0.0	149.4
2012	76.3	0.0	76.3	11.6	0.0	11.6	191.5	0.0	191.5
2013	81.3	0.0	81.3	13.1	0.0	13.1	202.7	0.0	202.7
2014	79.3	0.0	79.3	14.4	0.0	14.4	194.1	0.0	194.1
2015	71.5	0.0	71.5	15.1	0.0	15.1	167.5	0.0	167.5
2016	60.0	0.0	60.0	15.0	0.0	15.0	134.2	0.0	134.2
2017	48.7	0.0	48.7	14.1	0.0	14.1	104.8	0.0	104.8
2018	41.3	0.0	41.3	13.2	0.0	13.2	86.9	0.0	86.9
2019	35.0	0.0	35.0	12.0	0.0	12.0	71.0	0.0	71.0
Total	598.7	0.0	598.7	126.3	0.0	126.3	1,386.7	0.0	1,386.7

Commission-Approved Conservation Goals for PEF

	Residential								
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	40.6	43.9	84.5	63.7	19.0	82.7	99.6	190.3	289.9
2011	42.5	43.9	86.4	69.2	19.0	88.2	105.6	190.3	295.9
2012	45.5	43.9	89.4	73.2	19.0	92.2	114.7	190.3	305.0
2013	47.5	43.9	91.4	75.9	19.0	94.9	120.7	190.3	311.0
2014	49.4	43.9	93.3	78.6	19.0	97.6	126.8	190.3	317.1
2015	54.8	43.9	98.7	83.3	19.0	102.3	147.9	190.3	338.2
2016	63.3	43.9	107.2	94.1	19.0	113.1	135.8	190.3	326.1
2017	62.9	43.9	106.8	93.5	19.0	112.5	129.8	190.3	320.1
2018	57.4	43.9	101.3	86.0	19.0	105.0	117.7	190.3	308.0
2019	42.9	43.9	86.8	61.5	19.0	80.5	108.6	190.3	298.9
Total	506.6	439.0	945.6	779.1	190.0	969.1	1,207.1	1,903.0	3,110.1

	Commercial/Industrial								
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	13.7	0.0	13.7	5.3	0.0	5.3	31.1	0.0	31.1
2011	16.2	0.0	16.2	5.3	0.0	5.3	33.0	0.0	33.0
2012	25.5	0.0	25.5	11.4	0.0	11.4	35.9	0.0	35.9
2013	25.9	0.0	25.9	11.5	0.0	11.5	37.7	0.0	37.7
2014	26.4	0.0	26.4	11.5	0.0	11.5	39.6	0.0	39.6
2015	27.6	0.0	27.6	11.7	0.0	11.7	46.2	0.0	46.2
2016	27.1	0.0	27.1	11.6	0.0	11.6	42.5	0.0	42.5
2017	27.0	0.0	27.0	11.6	0.0	11.6	40.6	0.0	40.6
2018	25.7	0.0	25.7	11.4	0.0	11.4	36.8	0.0	36.8
2019	22.3	0.0	22.3	11.3	0.0	11.3	34.0	0.0	34.0
Total	237.3	0.0	237.3	102.6	0.0	102.6	377.4	0.0	377.4

Commission-Approved Conservation Goals for TECO

	Residential								
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	2.7	1.9	4.6	2.8	3.6	6.4	4.8	5.0	9.8
2011	4.7	1.9	6.6	4.9	3.6	8.5	9.0	5.0	14.0
2012	6.5	1.9	8.4	6.6	3.6	10.2	12.7	5.0	17.7
2013	8.0	1.9	9.9	7.9	3.6	11.5	15.6	5.0	20.6
2014	8.9	1.9	10.8	8.6	3.6	12.2	17.6	5.0	22.6
2015	9.0	1.9	10.9	8.0	3.6	11.6	18.0	5.0	23.0
2016	7.9	1.9	9.8	6.5	3.6	10.1	16.3	5.0	21.3
2017	7.1	1.9	9.0	5.2	3.6	8.8	14.4	5.0	19.4
2018	6.4	1.9	8.3	4.4	3.6	8.0	13.3	5.0	18.3
2019	5.9	1.9	7.8	3.8	3.6	7.4	12.3	5.0	17.3
Total	67.1	19.0	86.1	58.7	36.0	94.7	134.0	50.0	184.0

	Commercial/Industrial								
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	2.5	0.0	2.5	0.9	0.0	0.9	6.5	0.0	6.5
2011	3.6	0.0	3.6	1.1	0.0	1.1	10.6	0.0	10.6
2012	4.3	0.0	4.3	1.4	0.0	1.4	15.4	0.0	15.4
2013	5.1	0.0	5.1	1.3	0.0	1.3	16.2	0.0	16.2
2014	5.4	0.0	5.4	1.5	0.0	1.5	19.5	0.0	19.5
2015	6.0	0.0	6.0	1.7	0.0	1.7	20.9	0.0	20.9
2016	6.2	0.0	6.2	1.6	0.0	1.6	21.6	0.0	21.6
2017	6.3	0.0	6.3	1.6	0.0	1.6	21.8	0.0	21.8
2018	6.4	0.0	6.4	1.7	0.0	1.7	22.1	0.0	22.1
2019	6.3	0.0	6.3	1.7	0.0	1.7	21.7	0.0	21.7
Total	52.1	0.0	52.1	14.5	0.0	14.5	176.3	0.0	176.3

Commission-Approved Conservation Goals for Gulf

	Residential								
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	1.90	5.60	7.50	1.90	4.00	5.90	2.8	32.20	35.00
2011	2.70	5.60	8.30	2.50	4.00	6.50	5.4	32.20	37.60
2012	3.80	5.60	9.40	3.40	4.00	7.40	8.4	32.20	40.60
2013	4.90	5.60	10.50	4.50	4.00	8.50	11.6	32.20	43.80
2014	6.10	5.60	11.70	5.50	4.00	9.50	14.6	32.20	46.80
2015	7.20	5.60	12.80	6.90	4.00	10.90	18.0	32.20	50.20
2016	8.40	5.60	14.00	8.10	4.00	12.10	21.4	32.20	53.60
2017	9.10	5.60	14.70	8.70	4.00	12.70	23.2	32.20	55.40
2018	9.30	5.60	14.90	9.30	4.00	13.30	24.0	32.20	56.20
2019	9.50	5.60	15.10	9.70	4.00	13.70	24.5	32.20	56.70
Total	62.90	56.00	118.90	60.50	40.00	100.50	153.9	322.00	475.90

	Commercial/Industrial								
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	1.20	0.00	1.20	0.50	0.00	0.50	3.20	0.00	3.20
2011	1.60	0.00	1.60	0.60	0.00	0.60	5.60	0.00	5.60
2012	2.10	0.00	2.10	0.80	0.00	0.80	7.70	0.00	7.70
2013	2.40	0.00	2.40	0.90	0.00	0.90	9.50	0.00	9.50
2014	2.70	0.00	2.70	1.00	0.00	1.00	10.80	0.00	10.80
2015	2.90	0.00	2.90	1.00	0.00	1.00	11.70	0.00	11.70
2016	3.00	0.00	3.00	1.20	0.00	1.20	12.30	0.00	12.30
2017	3.20	0.00	3.20	1.10	0.00	1.10	12.70	0.00	12.70
2018	3.10	0.00	3.10	1.10	0.00	1.10	12.50	0.00	12.50
2019	3.10	0.00	3.10	1.10	0.00	1.10	11.90	0.00	11.90
Total	25.30	0.00	25.30	9.30	0.00	9.30	97.90	0.00	97.90

Commission-Approved Conservation Goals for FPUC

	Residential								
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2011	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2012	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2013	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2014	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2015	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2016	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2017	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2018	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2019	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
Total	2.0	N/A	2.0	1.3	N/A	1.3	5.1	N/A	5.1

	Commercial/Industrial								
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2011	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2012	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2013	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2014	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2015	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2016	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2017	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2018	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2019	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
Total	2.3	N/A	2.3	0.6	N/A	0.6	7.8	N/A	7.8

Commission-Approved Conservation Goals for OUC

	Residential			Commercial/Industrial		
Year	Summer (MW)	Winter (MW)	Annual (GWh)	Summer (MW)	Winter (MW)	Annual (GWh)
2010	0.50	0.20	1.80	0.70	0.70	1.80
2011	0.50	0.20	1.80	0.70	0.70	1.80
2012	0.50	0.20	1.80	0.70	0.70	1.80
2013	0.50	0.20	1.80	0.70	0.70	1.80
2014	0.50	0.20	1.80	0.70	0.70	1.80
2015	0.50	0.20	1.80	0.70	0.70	1.80
2016	0.50	0.20	1.80	0.70	0.70	1.80
2017	0.50	0.20	1.80	0.70	0.70	1.80
2018	0.50	0.20	1.80	0.70	0.70	1.80
2019	0.50	0.20	1.80	0.70	0.70	1.80
Total	5.00	2.00	18.00	7.00	7.00	18.00

Commission-Approved Conservation Goals for JEA

	Residential			Commercial/Industrial		
Year	Summer (MW)	Winter (MW)	Annual (GWh)	Summer (MW)	Winter (MW)	Annual (GWh)
2010	2.0	1.6	6.9	2.4	1.4	22.1
2011	2.0	1.6	6.9	2.4	1.4	22.1
2012	2.0	1.6	6.9	2.4	1.4	22.1
2013	2.0	1.6	6.9	2.4	1.4	22.1
2014	2.0	1.6	6.9	2.4	1.4	22.1
2015	2.0	1.6	6.9	2.4	1.4	22.1
2016	2.0	1.6	6.9	2.4	1.4	22.1
2017	2.0	1.6	6.9	2.4	1.4	22.1
2018	2.0	1.6	6.9	2.4	1.4	22.1
2019	2.0	1.6	6.9	2.4	1.4	22.1
Total	20.3	15.5	69.0	24.0	14.3	221.0

INCENTIVES

FPL, PEF, TECO, and Gulf took the position that incentives do not need to be established at this time, but rather should be evaluated and established, if necessary, through a separate proceeding. FPUC argued that utility-owned energy efficiency and renewable energy systems are supply-side issues that are not applicable to it as a non-generating utility. Both OUC and JEA argued that, because municipal utilities are not subject to rate-of-return regulation, the issue of incentives is not relevant to them. According to FIPUG, the type and amount of incentives and their impact on rates should determine whether incentives are established. FIPUG provided no additional comments on the issue of incentives for utilities in its brief or direct testimony. FSC argued that incentives should be established but offered no supporting comments in its brief and did not file testimony. While NRDC/SACE argued that we should establish an incentive that will allow utilities an opportunity to share in the net benefits that cost-effective efficiency programs provide customers, it agreed with the FEECA utilities that the issue of financial incentives should be deferred to a subsequent proceeding, with the caveat that incentives are only appropriate if linked to the achievement of strong goals.

Section 366.82(3)(c), F.S., requires this Commission to consider whether incentives are needed to promote both customer-owned and utility-owned energy efficiency and demand-side renewable energy systems. In addition, Section 366.82(9), F.S., authorizes this Commission to allow an investor-owned electric utility an additional return on equity of up to 50 basis points for exceeding 20 percent of its annual load-growth through energy efficiency and conservation measures. The statute further states that this Commission shall establish such additional return on equity through a limited proceeding. This provision clearly allows us to award an incentive based upon a utility's performance and specifies the procedural mechanism for doing so.

None of the parties favored establishing incentives as part of this proceeding, with the exception of FSC, who filed no supporting comments and did not file testimony. In addition, staff witness Spellman recommended that if we believe that at some point incentives are necessary and appropriate, then the specific mechanism can be developed, in accordance with the FEECA statutes, in a separate proceeding, but not at this time. There is limited discussion in the record regarding the need for performance incentives or penalties, or analysis of how they should be structured. We agree with witness Spellman that a more appropriate course of action is to address the issue of incentives in a future proceeding when the necessary analysis has been done and all interested stakeholders can participate.

Section 366.82(8), F.S., states:

> The commission may authorize financial rewards for those utilities over which it has rate setting authority that exceed their goals and may authorize financial penalties for those utilities that fail to meet their goals, including, but not limited to, the sharing of generation, transmission, and distribution cost savings associated with conservation, energy efficiency, and demand-side renewable energy systems additions.

An IOU may choose to petition this Commission for an additional return on equity based upon its performance at any time the company believes such an incentive to be warranted. This Commission, on its own motion, may initiate a proceeding to penalize a utility for failing to meet its goals.

We believe establishing incentives during this proceeding would unnecessarily increase costs to ratepayers at a time when consumers are already facing financial challenges. Increasing rates in order to provide incentives to utilities is more appropriately addressed in a future proceeding after utilities have demonstrated and we have evaluated their performance.

With regard to customer-owned energy-efficiency and demand-side renewable energy systems, incentives are typically provided through each DSM program. Our staff evaluates each program proposed by a utility prior to making a recommendation as to whether it should be approved. Part of our staff's evaluation process includes an analysis of the cost-effectiveness tests performed by the utility, including the appropriateness of any incentives the utility proposes to offer to customers taking advantage of a particular program as well as the cost and benefits to all customers. Therefore, in our view, a mechanism for providing customers with incentives is already in place and we should continue to make decisions about customer incentives on an individual program basis. We find that it is not necessary to establish additional incentives for customers at this time as doing so would result in higher rates for all customers.

Conclusion

We find that incentives to promote energy efficiency and demand-side renewable energy systems should not be established at this time. We have met the requirements of Section 366.82(3)(c), F.S., by considering, during this proceeding, whether incentives are needed to promote energy efficiency and demand-side renewable energy systems. We will be in a better position to determine whether incentives are needed after we review the utilities' progress in reaching the goals established in these dockets. We may establish, through a limited proceeding, a financial reward or penalty for a rate-regulated utility based upon the utility's performance in accordance with Section 366.82(8) and (9), F.S. Utility customers are already eligible to receive incentives through existing DSM programs, and should not be harmed by considering additional incentives in a separate proceeding.

CONSIDERATION TO IMPACT ON RATES

The four generating IOUs agreed that the impact on rates should be considered in the goal setting process. FPUC, JEA, and OUC believed that we must continue to consider the impact on rates as a primary determinant in setting goals under FEECA.

FIPUG claimed that it is important that rate impact not be overlooked when conservation goals are set and programs are evaluated. FSC believed there are also other factors to be considered by us when setting conservation goals for the public utilities.

NRDC/SACE contended that consideration of the impact on rates does not belong in the goal setting process because of the 2008 FEECA amendments. Further, NRDC/SACE contended that customers are more interested in their monthly utility bills than in rates and would benefit most if energy efficiency programs are widely available.

As specified in Section 366.01, F.S., the regulation of public utilities is declared to be in the public interest. Chapter 366 is to be liberally construed for the protection of the public welfare. Several sections within the Chapter, specifically Sections 366.03, 366.041, and 366.05, F.S., refer to the powers of the Commission and setting rates that are fair, just, and reasonable. The 2008 legislative changes to FEECA did not change our responsibility to set such rates.

Under FEECA, we are charged with setting goals and approving plans related to the promotion of cost-effective demand-side renewable energy systems and the conservation of electric energy. The 2008 changes to FEECA specified that this Commission is to take into consideration the costs and benefits of ratepayers as a whole, in addition to the cost and benefits to customers participating in a measure. FEECA makes it clear that we must consider the economic impact to all, both participants and non-participants. This can only be done by ensuring rates to all are fair, just, and reasonable.

When setting conservation goals there are two basic components to a rate impact: Energy Conservation Cost Recovery and base rates. The costs to implement a DSM Program consist of administrative, equipment, and incentive payments to the participants. These costs are recovered by the utility through the Energy Conservation Cost Recovery clause. Cost recovery is reviewed on an annual basis when true-up numbers are confirmed. When approved, the utility allocates that expense to its general body of ratepayers and rates immediately go up for all ratepayers until that cost is recovered. When new DSM programs are implemented or incentive payments to participants are increased, the cost of implementing the program will directly lead to an increase in rates as these costs are recovered.

Base rates are established by this Commission in a rate case. Between rate cases, we monitor the company's Return on Equity (ROE) within a range of reasonable return, usually + or – 1 percent or 100 basis points. If the ROE of a utility exceeds the 100 basis point range, we can initiate a rate case to adjust rates downward. If the ROE falls below the 100 basis point range, the utility may file a petition with this Commission for a rate increase.

Energy saving DSM programs can have an impact on a utility's base rates. Utilities have a fixed cost of providing safe, reliable service. When revenues go down because fewer kWh were consumed, the utility may have to make up the difference by requesting an increase in rates in order to maintain a reasonable ROE.

The downturn of the present economy, coupled with soaring unemployment, make rates and the monthly utility bill ever more important to utility customers. When speaking about customers who participate in a utility program and receive an incentive, FPL witness Dean testified that utility customers generally will use less energy and even though rates are higher for everyone, program participants purchase less energy and thus are net beneficiaries of the program because their lower consumption lowers their total bill. Witness Dean further testified that these costs disproportionately fall upon those who are unable to participate in programs. Similarly, JEA witness Vento testified that customers such as renters who do not or cannot implement a DSM measure, and therefore have no corresponding benefit of reduced consumption to offset the rate increase, will be subject to increased utility bills.

Witness Pollock also recognized the importance of conservation in lowering utility bills as all consumers "face challenging economic times." Witness Pollock testified that the importance of pursuing conservation programs must be balanced against their cost and impact of that cost on ratepayers. Witness Pollock further testified that consideration of rate impacts in the evaluation of conservation programs helps to minimize both rates and costs for ratepayers. Finally, PEF witness Masiello testified that this Commission should also balance the needs of all stakeholders and minimize any adverse impacts to customers.

Conclusion

As provided in Section 366.04, F.S., we are given ". . . jurisdiction to regulate and supervise each public utility with respect to its rates and service." In past FEECA proceedings, the impact on rates has been a primary consideration of this Commission when establishing conservation goals and approving programs of the public utilities. The 2008 legislative changes to FEECA did not diminish the importance of rate impact when establishing goals for the utilities.

Those who do not or cannot participate in an incentive program will not see their monthly utility bill go down unless they directly decrease their consumption of electricity. If that is not possible, non-participants could actually see an increase in the monthly utility bill. Since participation in DSM programs is voluntary and this Commission is unable to control the amount of electricity each household consumes, we should ensure the lowest possible overall rates to meet the needs of all consumers.

Section 366.82(7), F.S., states that this Commission can modify plans and programs if they would have an undue impact on the costs passed on to customers. We believe that the Legislature intended for this Commission to be conscious of the impact on rates of any programs we evaluate to meet goals.

SEPARATE GOALS FOR DEMAND-SIDE RENEWABLE ENERGY SYSTEMS

All seven FEECA utilities took the position that we should not establish separate goals for demand-side renewable energy systems. FPL believed that the FEECA amendments, in particular, Section 366.82(3), F.S., ". . . require this Commission to consider renewable energy systems in the conservation goal setting process." FPL contended that this statutory requirement was met because ITRON and FPL evaluated these resources in this goal setting process. FPL, PEF, TECO, and Gulf contended that demand-side renewable resources were evaluated as a part of the conservation goals analysis and these measures were not found to be cost-effective; therefore, a separate goal is not necessary. Gulf asserted that demand-side renewables should be evaluated with the same methodology that is used to evaluate energy efficiency measures. PEF currently offers demand-side renewable programs and is developing new initiatives. FPL noted that it will consider demand-side renewable measures in the program development stage. Gulf is currently evaluating a pilot solar thermal water heating program.

FPUC, OUC, and JEA contended that, in setting goals, there should not be a bias toward any particular resource. Otherwise, FPUC, OUC, and JEA stated that goals could be set without appropriate consideration of costs and benefits to the participants and customers as a whole as required by Section 366.82(a) and (b), F.S. In addition, JEA and OUC argued that as municipal utilities, they cannot recover costs for demand-side renewable programs through the Energy Conservation Cost Recovery clause. JEA and OUC also noted that both companies offer demand-side renewable programs.

FSC contended that Section 366.82, F.S., requires this Commission to establish separate goals for demand-side renewables. FSC recommended that to meet this statutory obligation, we should require the FEECA IOUs to offer solar PV and solar water heating rebate programs to both residential and commercial customers. Further, FSC stated that we should authorize each IOU to recover up to 1 percent of annual retail sales revenue (based on 2008 revenues) to fund rebates for the next five years. FSC suggested a rebate of $2 per watt for PV systems with a capacity up to 50 kW. FSC contended that we should establish a performance-based incentive program for PV systems with a capacity greater than 50 kW. FSC recommended that incentives be reduced over the five years to account for market development and any resulting reduction in PV prices. FSC did not take a position with respect to OUC and JEA, which each currently have programs to encourage customers to install solar resources.

Section 366.82(2), F.S., was amended in 2008. The entire text of Section 366.82(2), F.S., follows, with the amendments underlined.

> The Commission shall adopt appropriate goals for increasing the efficiency of energy consumption and <u>increasing the development of demand-side renewable energy systems</u>, specifically including goals designed to increase the conservation of expensive resources, such as petroleum fuels, to reduce and control the growth rates of electric consumption, to reduce the growth rates of weather-sensitive peak demand, <u>and to encourage development of demand-side renewable energy resources. The Commission may allow efficiency investments across generation, transmission, and distribution as well as efficiencies within the user base.</u>

Because of the revisions to the statute, we requested that the utilities address demand-side renewables in their cost-effectiveness analyses. As previously discussed, the first step in the utilities' cost-effectiveness analysis for demand-side renewables was the Technical Potential Study performed by ITRON. Witness Rufo testified that ITRON estimated the technical potential for one residential rooftop PV system, one commercial rooftop PV system, one commercial ground-mounted PV system, and solar domestic hot water heaters. Witness Rufo testified that ITRON did not estimate the achievable potential for PV systems "due to the fact that PV measures did not pass the cost-effectiveness criteria established by the FEECA utilities for purposes of this study, i.e., TRC, RIM, and/or the Participants Test." Witness Rufo further testified that incentive levels were not calculated for solar measures (for JEA and OUC) because these measures did not pass RIM or TRC without incentives.

FPL, TECO, Gulf, FPUC, OUC, and JEA did not include savings from solar measures toward their goals because no solar measures were found to be cost-effective. However, PEF, OUC, and JEA have existing solar programs. PEF currently offers two solar programs. PEF's Solar Water Heater with EnergyWise program combines a demand-response program with a rebate for solar water heaters. PEF's SolarWise for Schools program allows interested customers to donate their monthly credits from participating in a load control program to support the installation of PV systems in schools. Witness Masiello testified that PEF has also developed new solar initiatives that will possibly be included in PEF's DSM program filing. Witness Masiello further testified that a separate goal for demand-side renewables is not needed because PEF included these resources in its goals.

We believe that the amendments to Section 366.82(2), F.S., clearly require us to set goals to increase the development of demand-side renewable energy systems. As indicated above, the Section states that the "Commission shall adopt appropriate goals for increasing the efficiency of energy consumption and <u>increasing the development of demand-side renewable energy systems</u>. . . ." (Emphasis added) We believe that in making these amendments to Section 366.82(2), F.S., the Legislature has placed additional emphasis on encouraging renewable energy systems. FSC and NRDC/SACE argued that the amendments to 366.82(2), F.S., require goals for these resources. Witness Spellman testified that "the legislation clearly requires the Commission to focus some specific attention on demand-side renewable energy resources as part of its goal setting process."

As discussed above, none of the demand-side renewable resources were found to be cost-effective under any test in the utilities' analyses. In the past, we have set goals equal to zero in cases where no DSM programs were found to be cost-effective, for example, for JEA and OUC. Therefore, based purely on the cost-effectiveness test results, we have the option to set goals equal to zero for demand-side renewable resources. However, we note that by amending FEECA, the Legislature placed added emphasis on demand-side renewable resources. The Legislature has also recently placed emphasis on these resources by funding solar rebates through the Florida Energy and Climate Commission.

In its brief, FSC recommended that we should require the four largest IOUs to spend a specified annual amount on solar PV and solar thermal water heating programs. NRDC/SACE agreed with FSC's position. FSC suggested that solar water heaters and PV systems under 50 kW in capacity should receive an up-front rebate, while financial support to larger PV systems up to 2 MW should be performance-based. FSC recommended a rebate of $2 per watt for residential and commercial PV systems up to 50 kW in capacity. FSC suggested that annual support should continue for five years, and decrease every year to account for market development and reductions in technology costs. FSC took no position on requiring programs for FPUC, JEA, and OUC.

Witness Spellman acknowledged that none of the solar PV and solar thermal technologies included in the ITRON study and utility cost-effectiveness analyses were found to be cost-effective. However, witness Spellman testified that research and development programs on these technologies will provide benefits "because of their potential for more efficient energy production, the environmental benefits, and the conservation of non-renewable petroleum fuels." Witness Spellman believed that support for these technologies could result in lower costs over time. He also recommended that OUC and JEA be required to offer demand-side renewable programs, but recognized that we do not have ratemaking authority over these utilities. In order to protect the IOUs' ratepayers, utilities would be allowed to recover a specified amount of expenses through the Energy Conservation Cost Recovery clause. Witness Spellman did not advocate specific demand or energy savings goals for demand-side renewables. Witness Spellman suggested that these programs should focus on solar PV and solar water heating technologies, and did not believe that the demand and energy savings resulting from these programs should be counted toward a utility's conservation goals.

Witness Spellman recommended that expenditures on these solar programs should be capped at 10 percent of each IOU's five-year average of Energy Conservation Cost Recovery expenses for 2004 through 2008. These dollar amounts should be constant over the five year period until goals are reset. Witness Spellman recommended that the funds be used for up-front rebates on solar PV and solar water heating technologies for both residential and commercial customers.

Conclusion

We find that the amendments to Section 366.82(2), F.S., require us to establish goals for demand-side renewable energy systems. None of these resources were found to be cost-effective in the utilities' analyses. However, we can meet the intent of the Legislature to place added emphasis on these resources, while protecting ratepayers from undue rate increases by requiring the IOUs to offer renewable programs subject to an expenditure cap. We direct the IOUs to file pilot programs focusing on encouraging solar water heating and solar PV technologies in the DSM program approval proceeding. Expenditures allowed for recovery shall be limited to 10 percent of the average annual recovery through the Energy Conservation Cost Recovery clause in the previous five years as shown in the table below. Utilities are encouraged to design programs that take advantage of unique cost-saving opportunities, such as combining measures in a single program, or providing interested customers with the option to provide voluntary support.

Utility	Commission Approved Annual Expense
FPL	$15,536,870
Gulf	$900,338
PEF	$6,467,592
TECO	$1,531,018
FPUC	$47,233
Total	$24,483,051

ADDITIONAL GOALS FOR EFFICIENCY IMPROVEMENTS IN GENERATION, TRANSMISSION, AND DISTRIBUTION

We agree with FPL, PEF, TECO, and Gulf that goals need not be established for generation, transmission, and distribution in this proceeding. Gulf expanded the discussion arguing that guidelines have not been developed that would provide a methodical approach to identifying, quantifying, and proposing goals for supply-side conservation and energy efficiency measures. OUC and JEA both offered only that efficiency improvements in generation, transmission, and distribution are supply-side issues which are more appropriately addressed in the utilities' resource planning processes, thereby seeming to imply that such goal-setting has no place in a conservation goal-setting proceeding. FPUC, a non-generating IOU, took no position.

FSC's position suggested that the IOUs should conduct technical potential studies of efficiencies in generation, transmission, and distribution. Afterwards, this Commission should establish efficiency improvement goals in a separate proceeding. FSC took no position on the issue as it pertains to the two municipal utilities.

NRDC/SACE went a step further, arguing that increasing generating plant efficiency and reducing transmission and distribution losses benefit customers and the environment. They recommended that we set a date certain by which the companies will perform technical economic and potential studies for efficiency improvements at their existing facilities. However, they did not specifically suggest that we should set goals in these areas.

State legislative direction provides, "[t]he commission may allow efficiency investments across generation, transmission, and distribution . . . ." (Section 366.82(2), F.S.) Section 366.82(3), is more affirmative stating: "[i]n developing the goals, the commission shall evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures . . . ." (Emphasis added) The FEECA utilities performed no technical potential study of supply-side measures for this docket. The potential for supply-side improvements is an inherent element of the annual Ten-Year Site Plan submitted by each FEECA utility. Supply-side efficiency and conservation is also analyzed in every need determination for new sources of generation. In addition, efficiency improvements in generation, transmission, and distribution tend to reduce the potential savings available via demand-side management programs.

We believe that the utilities' motivation to deliver electric service to their customers in the most economically efficient means possible makes efficiency improvements in generation, transmission, and distribution a naturally occurring result of their operations. In the case of the five IOUs, such efficiency is inextricably tied to their efforts to make a profit. The two municipal utilities, while not driven by a profit motive per se, must still provide electrical service as efficiently and inexpensively as possible. Rule 25-17.001, F.A.C., supports this proposition because the rule states: ". . . general goals and methods for increasing the overall efficiency of the bulk electric power system of Florida are broadly stated since these methods are an ongoing part of the practice of every well-managed electric utility's programs and shall be continued."

Despite NRDC/SACE's observation that customers and the environment will benefit from facility efficiencies, they offer no evidence that utilities are not routinely seeking those efficiencies. FSC, in arguing that we should set goals in this area, likewise offers no support to suggest such action is warranted.

Conclusion

Efficiency improvements for generation, transmission, and distribution are continually reviewed through the utilities' planning processes in an attempt to reduce the cost of providing electrical service to their customers. With no evidence to suggest efficiency improvements in generation, transmission, and distribution are not occurring, we find that goals in these areas will not be set as part of this proceeding.

SEPARATE GOALS FOR ENERGY AUDIT PROGRAMS

The FEECA utilities, FIPUG, and FSC all agreed that separate goals for energy audits are not necessary. NRDC/SACE asserted that separate goals for residential and commercial/industrial customer participation in utility energy audit programs should be established by this Commission.

Section 366.82(11), F.S., mandates that we require utilities to offer energy audits and to report the actual results as well as the difference, if any, between the actual and projected results. The statute is implemented by Rule 25-17.003, F.A.C., which specifies the minimum requirements for performing energy audits as well as the types of audits that utilities offer to customers, and also details the requirements for record keeping regarding the customer's energy use prior to and following the audit. The utility can thereby ascertain whether the customer actually reduced his energy usage subsequent to the audit.

Witness Steinhurst testified that utility energy audit programs by themselves do not provide any direct demand reduction and energy savings. In order to conserve energy, the customer must implement some form of an energy saving measure. Witness Masiello testified that most if not all utilities require that an audit be performed before a customer can participate in DSM programs administered by the utility. This requirement means that having separate goals for audits would be duplicative, because the energy savings and demand reduction following the audits would be attributed to the individual measures that were recommended and implemented as a result of the audit, and therefore would already be counted towards savings goals. Witness Spellman testified that savings associated with energy saving measures installed by customers following a utility audit should be counted towards the savings of the particular program through which they obtained the measure and not the energy audit service. Witness Bryant testified that this is the method typically used to account for these savings.

Conclusion

The energy conservation achieved through customer education is included in the overall conservation goals and should be credited to the specific program into which the customer enrolls. In order to avoid duplication of demand reduction and energy savings, we find that no separate goals for participation in utility energy audit programs need be established.

EFFICIENT USE OF COGENERATION

FPL, PEF, Gulf, and TECO argued that no further action is needed concerning cogeneration due to the 2008 Legislative changes that were made to the FEECA statutes. Further, the Commission has addressed cogeneration in Chapter 25-17, F.A.C. FPUC, OUC, and JEA took no position on the issue of cogeneration. NRDC/SACE and FIPUG contended that there are barriers to the cogeneration process due to the unfair compensation rates afforded cogenerators by rule. Other parties were silent on the issue.

The Legislature recognizes the benefits of cogeneration in Section 366.051, F.S., where utility companies are required to purchase all electricity offered for sale by the cogenerator as outlined in Rule 25-17.082, F.A.C. We periodically establish rates for cogeneration equal to the utilities full avoided cost as guidelines for the purchase of energy. Rule 25-17.015, F.A.C., also allows each utility to recover its costs for energy conservation through cost recovery.

The FEECA utilities agree that this Commission need not take action regarding cogeneration in this goal setting proceeding. The 2008 Florida Legislature removed the term "cogeneration" from the FEECA statute, Section 366.82(2), F.S., replacing it with "demand side renewable energy systems." The utilities contend that cogeneration is not to be considered part of the FEECA ten-year goal setting process. The utilities also contend that cogeneration systems must be evaluated on a site-specific, case-by-case basis, which does not lend itself to the FEECA conservation goals-setting process. The FEECA proceedings were commenced to set overall conservation goals for the FEECA utilities, and not designed as proceedings to focus on promoting cogeneration.

FIPUG believes there are barriers to the cogeneration process established by Commission Rule, which prevent industrial customers from full compensation for electricity generated by their cogeneration processes. FIPUG also believes it is a disadvantage if customers operate facilities at two or more different locations and cannot construct their own transmission lines to those locations. FIPUG contended cogenerator repayment at the utility's average fuel cost is much lower than the utility rate and that the reimbursement rate does not encourage cogeneration. The Legislature addressed the transmission and compensation issue of cogenerators in Section 366.051, F.S. This Commission has established "Conservation and Self-service Wheeling Cost" in Rule 25-17.008 F.A.C., "Energy Conservation Cost Recovery" in Rule 25-17.015 F.A.C., and "The Utility's Obligation to Purchase" in Rule 25-17.082 F.A.C.

Conclusion

The Florida Legislature recognizes cogeneration in Section 366.051, F.S., and in 2008 removed the term "cogeneration" from the FEECA statutes, Section 366.82, F.S. Cogeneration is encouraged by this Commission as a conservation effort, as evidenced by Rules 25-17.080 – 25-17.310, F.A.C. Therefore, the goals set do not need to address issues relating to cogeneration in this proceeding.

COMMISSION AUTHORITY OVER OUC AND JEA

Under FEECA, we have jurisdiction over OUC and JEA's conservation goals and plans. Section 366.81, F.S. (2008), states in pertinent part:

> The Legislature . . . finds that the Florida Public Service Commission is the appropriate agency to adopt goals and approve plans . . . . The Legislature directs the commission to develop and adopt overall goals and authorizes the commission to require each utility to develop plans and implement programs for increasing energy efficiency and conservation and demand-side renewable energy systems within its service area, subject to the approval of the commission. . . . The Legislature further finds and declares that ss. 366.80-366.85 and 403.519 [FEECA] are to be liberally construed . . . .

(Emphasis added)

For purposes of the FEECA statutes, Section 366.82(1)(a), F.S. (2008), defines a utility as being:

> "Utility" means any person or entity of whatever form which provides electricity or natural gas at retail to the public, specifically including municipalities or instrumentalities thereof . . . specifically excluding any municipality or instrumentality thereof, . . . providing electricity at retail to the public whose annual sales as of July 1, 1993, to end-use customers is less than 2,000 gigawatt hours.

(Emphasis added)[12] Section 366.82(2), F.S., provides "[t]he commission shall adopt appropriate goals for increasing the efficiency of energy consumption . . . ."

Our statutory jurisdiction to set goals under FEECA is clear. The Legislature has required that we develop, establish, and adopt appropriate conservation goals for all utilities under the jurisdiction of FEECA. According to Section 366.82(1)(a), F.S., both OUC and JEA, as municipal utilities with sales exceeding 2,000 gigawatt hours, fall under our FEECA jurisdiction. Therefore, we must adopt appropriate conservation goals for OUC and JEA pursuant to Section 366.82(2) and (3), F.S.

Furthermore, this Commission has previously addressed whether it is prohibited under FEECA from considering conservation programs, and by correlation, goals that would increase rates for municipal and cooperative electric utilities. In Order No. PSC-93-1305-FOF-EG, issued September 8, 1993, this Commission considered that question and determined that FEECA contains no such prohibition, but this Commission would, as a matter of policy, attempt to set conservation goals that would not result in rate increases for municipal utilities.[13]

We disagree with OUC and JEA's assertion that, because we lack ratemaking authority over these utilities, we are prohibited from establishing goals that might put upward pressure on rates. Ratemaking for public utilities is governed under Sections 366.06 and 366.07, F.S. Pursuant to Section 366.02(2), F.S., municipal and cooperative electric utilities are specifically excluded from the definition of public utility, and thus, we do not have ratemaking jurisdiction over these utilities. We believe that adopting conservation goals, or approving conservation programs, pursuant to FEECA is not ratemaking within the meaning of Chapter 366, F.S. We believe that the setting of conservation goals under FEECA for municipal electric utilities, therefore, does not infringe upon the municipal electric utilities' governing boards' authority to set rates.

At this time, it would be difficult to ascertain what affect, if any, the approved conservation goals would actually have upon OUC and JEA's rates. Given the multitude of variables which also place upward and downward pressure on rates, we believe that OUC and JEA's assertions that conservation goals alone would add upward pressure on rates is speculative at best. In the instant case, we believe that the proposed conservation goals for OUC and JEA should not apply upward pressure on the rates of OUC and JEA's customers, especially

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[12] The language of Section 366.82(1)(a), F.S., was amended in 1996 by the Legislature to exclude municipal electrics and Rural Cooperatives with annual sales less than 2,000 gigawatt hours. See s. 81, Ch. 96-321, Laws of Florida.

[13] See Order No. PSC-93-1305-FOF-EG, issued September 8, 1993, in Docket Nos. 930553-EG, 930554-EG, 930555-EG, 930556-EG, 930557-EG, 930558-EG, 930559-EG, 930560-EG, 930561-EG, 930562-EG, 930563-EG, 930564-EG, In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by City of Gainesville, City of Jacksonville Electric Authority, Kissimmee Electric Authority, City of Lakeland, Ocala Electric Authority, Orlando Utilities Commission, City of Tallahassee, Clay Electric Cooperative, Lee County Electric Cooperative, Sumter Electric Cooperative, Talquin Electric Cooperative, Withlacoochee River Electric Cooperative (hereinafter, 1993 FEECA Municipal DSM Goals Proceedings), at 5.

considering that the approved goals are based upon the conservation programs that OUC and JEA are currently implementing.

With regard to Order No. PSC-95-0461-FOF-EG, issued April 10, 1995, cited by OUC and JEA, the Commission stated:

> We believe that as a guiding principle, the RIM test is the appropriate test to rely upon at this time. The RIM test ensures that goals set using this criteria would result in rates lower than they otherwise would be. All the municipal and cooperative utilities, with the exception of Tallahassee, stipulated to cost-effective demand and energy savings under the RIM test. However, Tallahassee's stipulated goals are higher than that cost-effective under RIM. . . . The Commission does not have rate setting authority over municipal and cooperative utilities. Therefore, we find it suitable to allow the governing bodies of these utilities the latitude to stipulate to the goals they deem appropriate regardless of cost-effectiveness.

Id. at 4-5 (Emphasis added) In 1995, this Commission recognized the RIM test as a "guiding principle" for setting goals for municipal and cooperative electric utilities, but the 2008 Legislative changes to FEECA have superseded this "guiding principle" consideration. We are now required to establish goals for all FEECA utilities pursuant to the requirements of Section 366.82(3), F.S., as amended and previously discussed.

Moreover, the order cited by OUC and JEA is distinguishable from the instant case because this Commission did not "set goals" for OUC and JEA but merely approved stipulated goals for these two utilities. The stipulated goals resulted from a settlement between OUC and JEA and the Florida Department of Community Affairs (DCA).[14] Here, the goals being proposed for these utilities are not stipulated goals but are proposed goals following a full evidentiary hearing.

Conclusion

We have the authority to adopt conservation goals for all electric utilities under the jurisdiction of FEECA. OUC and JEA come within the meaning of utility as defined by FEECA. Developing, establishing, and adopting conservation goals is a regulatory activity exclusively granted to this Commission by FEECA and is not ratemaking within the meaning of Chapter 366, F.S. Therefore, we find that we have the authority to develop, establish, and adopt conservation goals for OUC and JEA as required by Section 366.82, F.S.

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[14] See Order No. PSC-95-0461-FOF-EG, issued April 10, 1995, In re: 1993 FEECA Municipal DSM Goals Proceedings. The DCA intervened in the 1993 DSM Goals Proceedings on behalf of the Governor of Florida. All the municipal and cooperative electric utilities who were parties to the 1993 DSM Goals Proceedings reached joint stipulations with DCA regarding conservation goals.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Florida Power & Light Company's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Progress Energy Florida, Inc.'s residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Progress Energy Florida, Inc.'s commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Gulf Power Company's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Gulf Power Company's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Tampa Electric Company's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Tampa Electric Company's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Florida Public Utilities Company's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Florida Public Utilities Company's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that OUC's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that OUC's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that JEA's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that JEA's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that within 90 days of the issuance of this Order, each utility shall file a demand-side management plan designed to meet the utility's approved goals. It is further

ORDERED that these dockets shall be closed if no appeal is filed within the time period permitted for filing an appeal of this Order.

By ORDER of the Florida Public Service Commission this 30th day of December, 2009.

Ann Cole

ANN COLE
Commission Clerk

(S E A L)

KEF

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

Office of Energy

Annual Report 2014

Updated February 13, 2015

Florida Department of Agriculture and Consumer Services

Adam H. Putnam, Commissioner

Dear Governor Scott, President Gardiner and Speaker Crisafulli,

I am pleased to provide you with the 2014 Annual Report of the Florida Department of Agriculture and Consumer Services' Office of Energy (FDACS OOE). This report reflects the FDACS OOE activities during 2014 and elaborates on the programs undertaken to help prepare Florida to meet the growing demand for energy in a diverse and sustainable manner.

A few of the highlights for this past year include:

- Florida's Renewable Energy Tax Incentives program provided nearly $24 million in incentives and produced an estimated economic contribution of more than $261.9 million with 909 jobs created and raised $21.7 million in state and local taxes.

- The Natural Gas Fuel Fleet Vehicle Rebate Program provided approximately $3.8 million in incentives during its first 6 months and produced an investment of $79.3 million with 382 jobs created or retained as a result of this program.

- Florida's first sales tax holiday weekend on ENERGY STAR and WaterSense products proved a success. This program not only helped customers save an estimated $1.6 million at the check-out counter, but will also save them energy, water and money on their bills over the long-term. Retailers reported large increases in sales over the previous year and provided positive feedback about the initiative.

I look forward to continue working with you to advance Florida's energy policy and support Florida's businesses, consumers and education infrastructure.

Sincerely,

Adam H. Putnam
Commissioner of Agriculture

FLORIDA DEPARTMENT OF AGRICULTURE AND CONSUMER SERVICES

OFFICE OF ENERGY

2014 ANNUAL REPORT

Adam H. Putnam, Commissioner

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1. Executive Summary

The Florida Department of Agriculture and Consumer Services' Office of Energy (FDACS OOE) is the legislatively designated state energy policy and program development office within Florida. The FDACS OOE evaluates energy related studies, analyses and stakeholder input in order to recommend to the Governor and Legislature energy policies and programs that will move Florida toward a more diversified, stable and reliable energy portfolio. Further, FDACS OOE uses available state and federal funds to develop and manage energy efficiency, renewable energy and energy education programs throughout the state.

This report reflects the FDACS OOE activities during 2014 and elaborates on the programs undertaken to help prepare Florida to meet the growing demand for energy in a diverse and sustainable manner. This report is submitted as required in Section 377.703(2)(f), Florida Statutes.

The FDACS OOE worked with Commissioner of Agriculture Adam H. Putnam to introduce energy proposals for consideration by the Legislature in 2014. Those recommendations were designed to help Florida capitalize on energy opportunities, use energy wisely and create jobs. Proposals included reducing energy tax costs for commercial businesses and using remaining tax revenues to provide a sustainable funding source for Florida's education infrastructure, as well as establishing the first ENERGY STAR and WaterSense Sales Tax Holiday in the state. This legislatively approved program helped Floridians not only save money at the check-out counter, but also save energy, water and money on their utility bills over time.

FDACS OOE continued to administer several renewable and alternative energy programs. Those programs included the Florida Renewable Energy Tax Incentives and the Natural Gas Fuel Fleet Vehicle Rebate Programs, both of which encourage the development and use of alternative fuels and create jobs in Florida.

It is important that Florida continue to evaluate its energy policy and update it to reflect changes in the industry, but also to continue to embrace the goals that are long term in nature and provide for a consistent and predictable energy policy that will improve the lives of all Floridians.

2. Florida's Energy Landscape

This chapter summarizes Florida's energy profile; it includes information on fuel diversity, electric generation, electric rates, infrastructure, transportation fuels, renewable fuels and energy efficiency measures. In addition to providing a summary of Florida's energy landscape, this chapter provides an outlook on potential areas of opportunity for the state.

2.1 Florida's Overall Consumption of Energy (Electricity and Transportation Fuel)

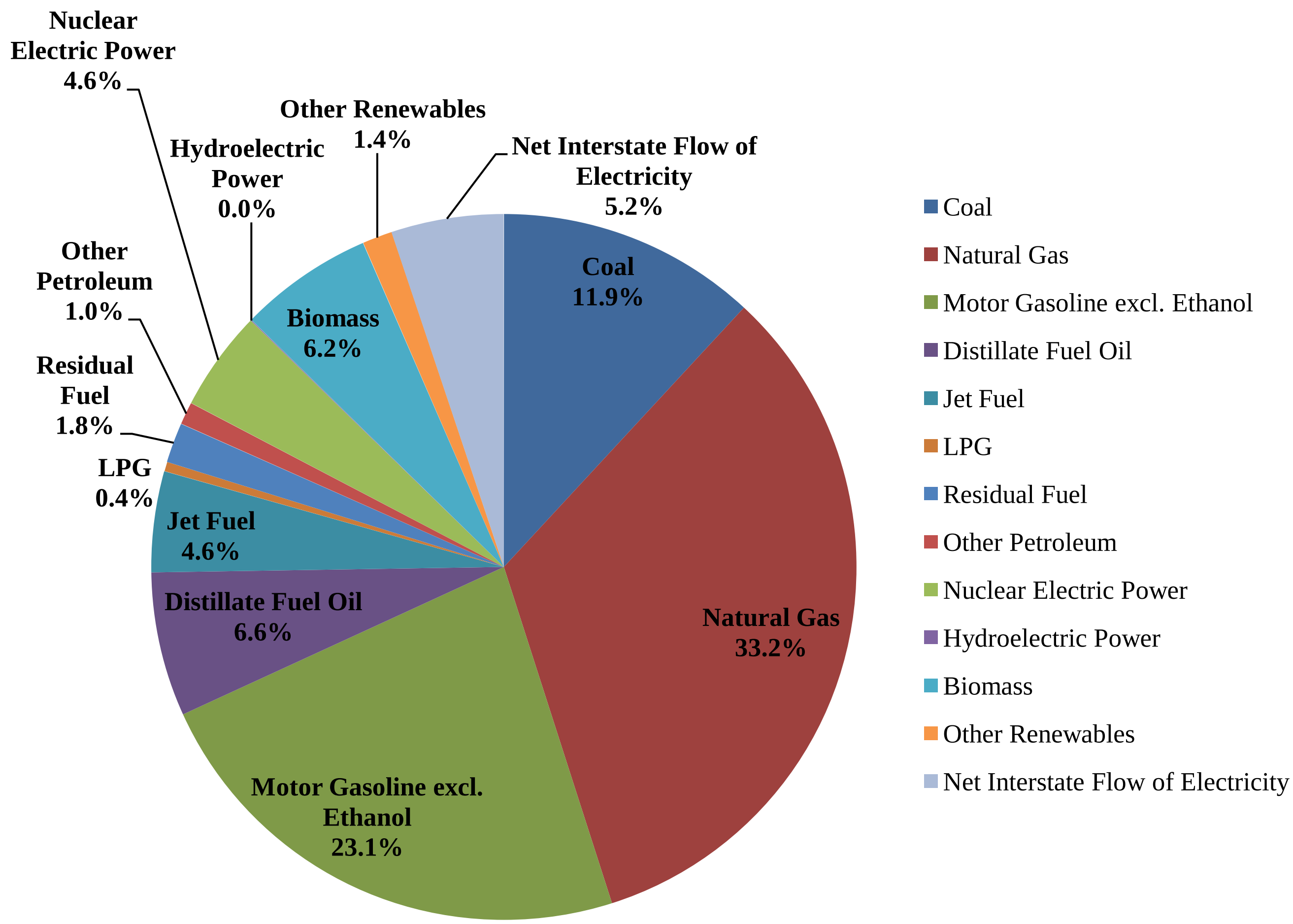
Florida is home to approximately 19 million people, and, as of December 2014, it is the third most populous state, according to the U.S. Census. With a population size of this magnitude, addressing Florida's energy needs are a top priority. As it relates to consumption, the United States Department of Energy's Energy Information Administration (US EIA) considered Florida to be the third largest energy-consuming state; however, in terms of per-capita energy consumption, Florida ranks 44th in the nation, consuming 210 million Btu[1]s per person.

Florida's lower per-capita energy consumption ranking, relative to the national average, is due to below average industrial sector consumption. What drives energy consumption in the state is the transportation and residential sectors. In terms of electric generation and transportation fuel, Florida is heavily reliant on natural gas and petroleum. Florida consumes more energy than it produces, making it a net energy importer of natural gas and petroleum products.

The most recent Florida energy consumption data provided by US EIA is for the year 2012 and is provided in Figure 1. Figure 1 demonstrates the various fuel sources comprising Florida's energy landscape. Natural gas continues to be the dominant fuel source for traditional electricity generation. The figure further demonstrates that Floridians consumed 1,348.4 trillion Btus of natural gas in 2012, or 33.2 percent of its total energy consumption. Floridians also consumed 938.3 trillion Btus of motor gasoline, or 23.1 percent of total energy consumption for all sectors—residential, commercial, industrial, and transportation.

[1] British Thermal Unit (Btu) is a standard unit for measuring a quantity of heat. The unit is used to measure and compare the energy content of fuel.

Figure 1: Florida Energy Consumption Estimates 2012
Source: US EIA



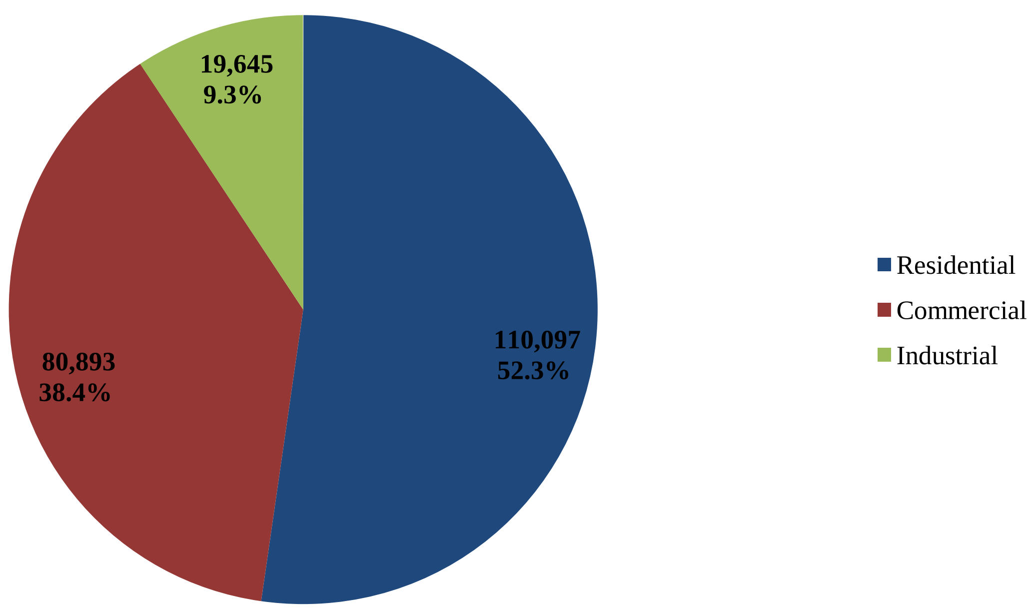
The Florida Public Service Commission (PSC) in its *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities* stated that "natural gas has become the dominant fuel in Florida within the last ten years…and is anticipated to serve future growth until the end of the planning period, when additional nuclear generation comes online." As of December 31, 2013, the Florida Reliability Coordinating Council (FRCC) reports that Florida's total electric generating capacity is 62,133 megawatts (MW), and the *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities* discusses the planned addition of approximately 12,570 MW of new utility-owned generation over the next ten years.

Florida receives the majority of its natural gas supplies from the Gulf Coast region, via two interstate pipelines: the Florida Gas Transmission line, and the Gulfstream pipeline. The Florida Gas Transmission line runs from Texas through the Florida Panhandle to Miami, and the Gulfstream pipeline is an underwater link from Mississippi and Alabama to central Florida. The Jacksonville area also receives supplies from the liquefied natural gas (LNG) import terminal at Elba Island, Georgia via the Cypress Pipeline. Florida Power & Light is planning to build a third major pipeline through the center of the state coming from Georgia which would increase natural gas supplies to the state.

Nuclear energy capacity in Florida is projected to increase slightly during the current 2014 ten-year planning period. There are four online nuclear power plants in the state, all of which are owned by Florida Power & Light (FPL). Nuclear energy is capital intensive in nature and requires a significant amount of lead time to construct. FPL is the only Florida electric utility that has a planned addition of two new nuclear units within the next ten years, according to the PSC's *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities*. The two new proposed units, Turkey Point units 6 and 7, have in-service dates scheduled for 2022 and 2023, respectively.

Florida's humid and warm climate leads to an increased demand for energy in order to address the state's cooling needs. In terms of electricity usage, Florida's residential sector consumes the majority of energy generated, as compared with the commercial and industrial sectors. In 2013, Florida's residents consumed 110,097 gigawatt hours (GWh), or 52.3 percent of all electric energy consumed in the state, as demonstrated in Figure 2 below. The PSC stated in its *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities* that Florida has 8,503,879 residential electric customers; comprising 88.7 percent of all electric customers in the state, with the remaining 11.3% made up of commercial and industrial users.

Figure 2: Energy Usage in 2013 (GWh)
Source: PSC 2014 Ten-Year Site Plan Review

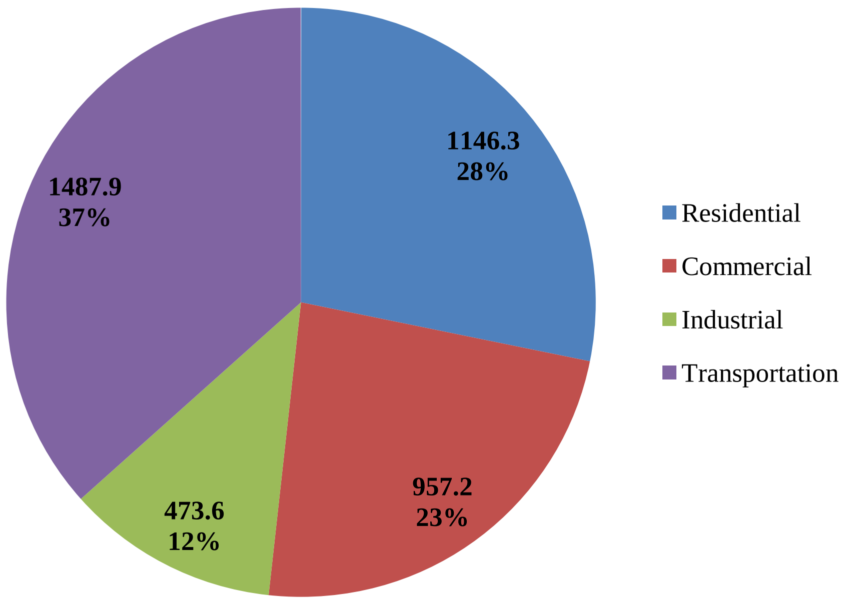


With Florida being the third most populous state, transportation fuel consumption is high relative to the rest of the nation. According to the US EIA, Florida is ranked third in the nation in terms of transportation fuel consumption, using 1,487.9 trillion Btus; this accounts for 5.6 percent of the total United States share of transportation fuel.

Florida has no oil refineries to serve the state's transportation sector and relies on petroleum products delivered by tanker and barge to marine terminals near the state's major coastal cities. Due in part to

Florida's tourist industry, demand for petroleum-based transportation fuels (motor gasoline and jet fuel) is among the highest in the United States, Figure 3, below, illustrates that the transportation sector accounts for the majority of energy consumed in the state.

Figure 3: Florida 2012 Energy Consumption by End-Use Sector (Trillion Btu)
Source: US EIA

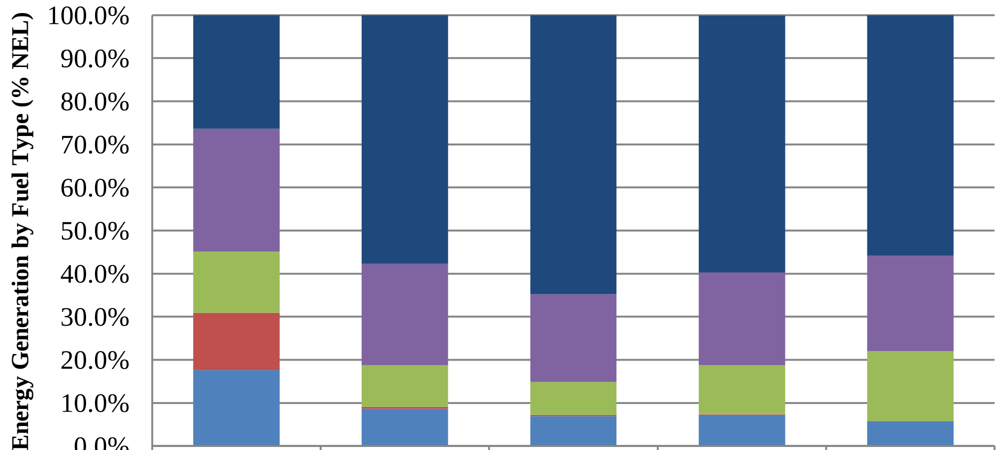


2.2 Florida Sources of Energy in the Power Sector

Florida's power sector utilizes various fuel sources in order to address the state's electrical needs. Figure 4 shows the mix of fuel sources Florida uses to generate electricity, including a projection to 2023. Figure 4 also shows Florida's electric generation in 2003, which highlights a time period when Florida's electric utilities attempted to maintain a more balanced fuel mix compared with today's fuel mix. Natural gas is the dominant fuel source for electricity as of 2013, currently comprising approximately 60% of Florida's electric generation and projected to continue at that percentage through 2023.

Figure 4: Florida Electric Generation Fuel Source Mix

Source: PSC Ten Year Site Plan Review 2012, 2013, 2014



	2003 Actual	2011 Actual	2012 Actual	2013 Actual	2023 Projected
Natural Gas*	26.5%	57.7%	64.8%	59.6%	55.8%
Coal	28.5%	23.6%	20.3%	21.6%	22.2%
Nuclear	14.2%	9.6%	7.7%	11.3%	16.2%
Oil**	13.3%	0.5%	0.3%	0.2%	0.1%
Interchange, Renewable, NUG, Other	17.6%	8.6%	6.9%	7.2%	5.7%

** Includes both utility and non-utility generation*
*** Includes both residual and distillate oil*

In the past, Florida's utilities adopted more of a balanced approach in terms of its electric generation fuel source mix. By building diverse plants that utilize different fuel sources, it provides a stability mechanism if one fuel source became unavailable or too costly. For example, in 2009, Florida's coal and nuclear plants provided stability from the highly volatile natural gas prices. Over time, Florida's utility industry has moved away from this balanced approach. This change is based on a number of factors including:

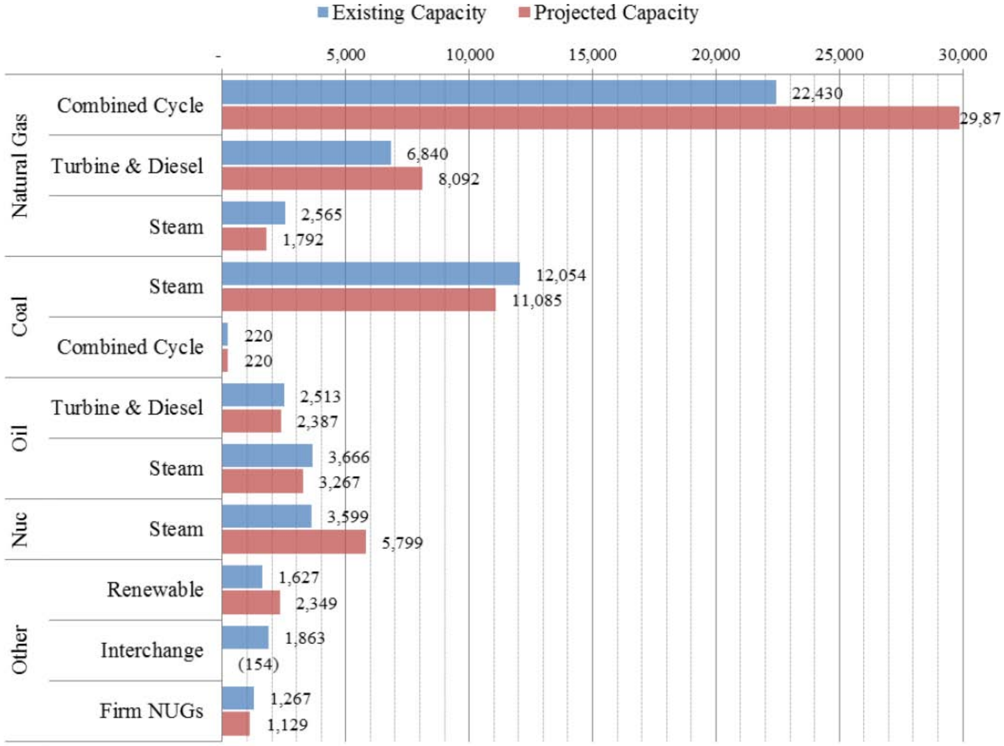
- Cleaner and less expensive natural gas generation facilities
- The high cost, lengthy permitting and construction time of nuclear power facilities
- The high environmental and regulatory cost of coal generation

Future Electric Generation Capacity, Facilities, and Retirements

Florida's electric utilities plan for future generating capacity in order to meet the growing demand for energy from their constantly increasing customer base. The electric utilities also plan on generation facility retirements or phase outs, and these plans are done on a ten-year rolling basis. Figure 5 below, highlights the current installed capacity and the 2023 projected capacity.

Figure 5: Florida Current and Projected Installed Capacity by Fuel and Technology (MW)

Source: PSC 2014 Ten-Year Site Plan Review, page 39, Figure 17



Electric Rates

The rates for residential customers in Florida vary from utility to utility. They are based on many factors including the number of customers they serve, whether they generate their own electricity (or purchase it from another utility), and what type of fuel source provides their electricity, such as natural gas, nuclear, and coal. The following is a brief synopsis of the PSC's Comparative Rate Statistics as of December 31, 2013:

Table 1: Residential Utility Rate Comparison High/Low per 1,000 kWh			
Investor-Owned Electric Utilities	Average Bill	High	$131.96
	$115.05	Low	$92.73
Municipal Electric Utilities	Average Bill	High	$141.15
	$119.40	Low	$100.49
Cooperative Electric Utilities	Average Bill	High	$146.99
	$128.53	Low	$113.50

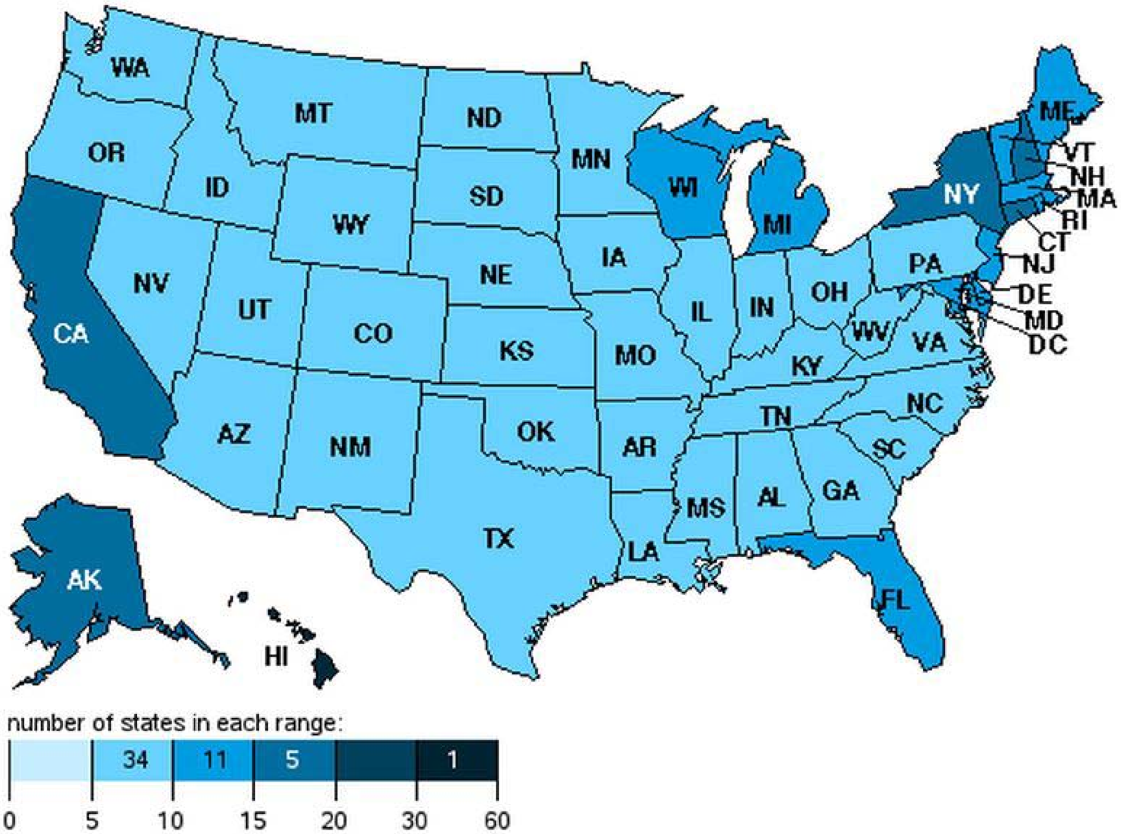
Source: PSC December 2013 Comparative Rate Statistics

Table 2: Commercial/Industrial Utility Rate Comparison High/Low per 150,000 kWh			
Investor-Owned Electric Utilities	Average Bill	High	$16,128.00
	$14,612.67	Low	$12,900.00
Municipal Electric Utilities	Average Bill	High	$22,125.00
	$17,329.47	Low	$13,188.00
Cooperative Electric Utilities	Average Bill	High	$19,899.00
	$16,003.25	Low	$13,702.00

Source: PSC December 2013 Comparative Rate Statistics

In November 2014, the average of all of Florida's electric rates (residential, commercial and industrial) was 11.00 cents per kilowatt hour (kWh) of electricity, which is slightly higher than the national average of 10.15 cents per kWh (US EIA). Florida's residential rates, however, are lower than the national average— 12.20 cents per kWh of electricity, as compared with the national average of 12.46 cents per kWh.

Figure 6: U.S. Electric Industry Average Revenue per Kilowatt-hour, November 2014

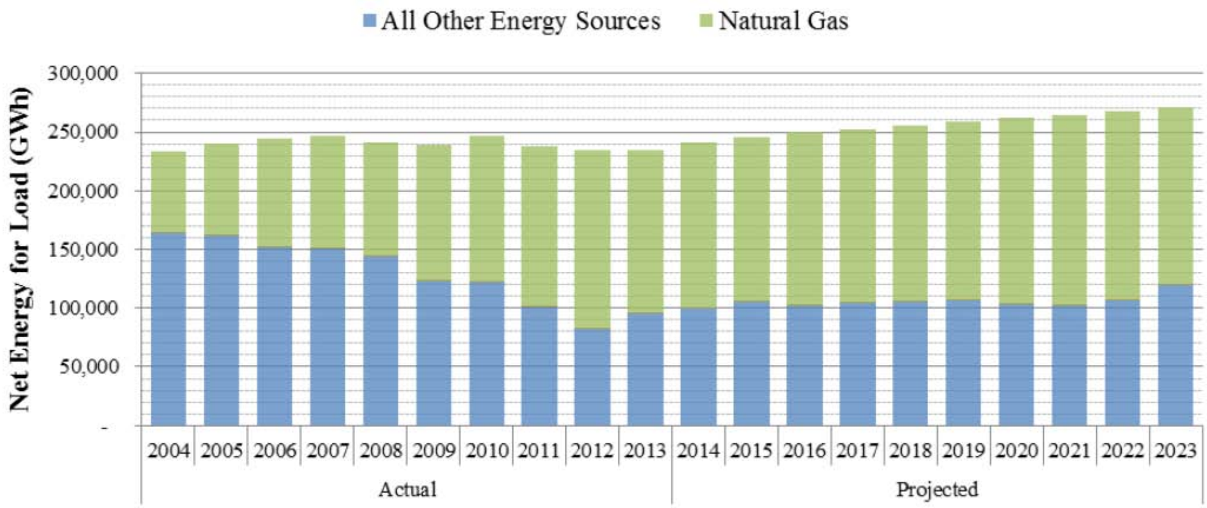


Source: Energy Information Administration [*http://www.eia.gov/electricity/monthly/update/end_use.cfm#tabs_prices-3*](http://www.eia.gov/electricity/monthly/update/end_use.cfm#tabs_prices-3)

Natural Gas Usage

Natural gas has grown from being one of many sources of energy used in Florida to being the dominant fuel source for electric generation. The price of natural gas has dropped significantly primarily due to increases in technological innovation. Figure 7 shows how natural gas compares to all energy sources used in Florida's energy consumption; the figure also contains projections to 2023.

Figure 7: Natural Gas Contribution to Florida Energy Consumption



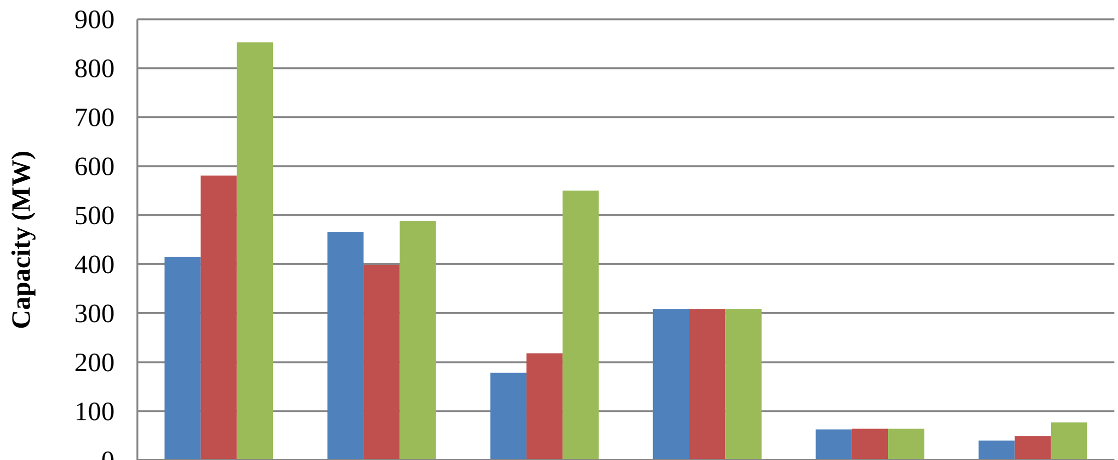
Source: PSC 2014 Ten-Year Site Plan Review, Figure 15, pg. 37

Renewable Energy

According to the PSC's *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities*, Florida's renewable energy facilities currently provide approximately 1,617 MW of generating capacity, representing 2.8 percent of Florida's overall generation capacity; eighty-four percent of this existing generation capacity comes from non-utility generators. As of December 2014, Florida has planned for an additional 722 megawatts of renewable energy by 2023, with the majority anticipated to come from solar and biomass projects.

Figure 8: Renewable Energy Capacity Comparison (MW)

Source: PSC 2014 Ten Year Site Plan Review



	Solid Biomass	MSW	Solar	Waste Heat	Hydro	Landfill Gas
2013	415	466	178	308	63	40
2014	581	398	218	308	64	49
Planned	853	488	550	308	64	77

As shown in Figure 8, as of 2014, solid biomass is the largest source of renewable energy in Florida, and is expected to remain so through 2023. Due to Florida's year-round growing season, Florida has more biomass resources than any other state. According to the Florida Energy Systems Consortium (FESC), Florida has the potential to account for seven percent of the U.S. total biomass resources. Energy production from biomass processing also has the potential to be a significant economic driver, especially in rural locations. However, in most cases, the bio-energy facility must be located near the intended feedstock to make the process economically viable.

Florida's second largest source of renewable energy comes from municipal solid waste (MSW). MSW uses residential waste as a feedstock and burns the waste to create steam which turns the electricity producing turbine. As of 2014, MSW accounts for 398 megawatts of electrical capacity in Florida, and is expected to grow to 488 megawatts by 2023. MSW facilities are equipped with advanced scrubbers to remove pollutants and reduce emissions. MSW is attractive to major population centers, because it diverts waste from entering the existing overburdened landfills while providing the benefit of a renewable energy source.

Currently, Florida's solar capacity is 218 megawatts which includes approximately 63 MW of customer owned renewable capacity from nearly 6,700 systems. Those 63 MW represents a 60 MW increase of distributed solar generation since 2008. While lagging behind waste heat as a fuel source, solar is expected to be the second largest renewable energy source by 2023 at 550 megawatts. It is generally expected that 550 megawatts is a low estimate considering Florida Power & Light's recently announced their plans to install an additional 225 MW of solar by 2016; the main driver of solar installations is the declining costs of photovoltaic panels. Additionally, there are major initiatives, such as the Sunshot Initiative, that are focusing on reducing the "soft costs" of solar which will increase the economic viability of solar. Soft costs include permitting, labor, and financing.

Waste heat currently provides 308 megawatts of renewable generation capacity, and is expected to remain constant through 2023. Large industries, such as orange juice processors, can create waste heat while manufacturing their products. To capture and utilize that waste heat they must redirect the waste heat or steam from their manufacturing process into a turbine to produce electricity. The process of capturing and redirecting the heat or steam is a large undertaking. Often times the excess heat is used to offset energy usage by heating the building, sterilizing equipment, or heating water instead of direct energy production.

2.3 Florida's Energy Efficiency and Conservation Efforts

In 1980, the Florida Legislature enacted the Florida Energy Efficiency and Conservation Act (FEECA), which made reducing Florida's peak electric demand and energy consumption a statutory objective. FEECA requires utilities reduce the growth rates of electric demand, conserve expensive resources, increase the overall efficiency and cost-effectiveness of electricity and reduce energy consumption. There are seven utilities that are statutorily subject to FEECA. The five investor-owned utilities - Florida Power & Light, Duke Energy of Florida, Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Company, and two large municipally-owned utilities - Orlando Utilities Commission and Jacksonville Electric Authority. FEECA requires the PSC to set appropriate energy efficiency and conservation goals for the utilities and requires a review of those goals at least once every five years with the most recent review during 2014.

In July of 2014, the PSC held an evidentiary hearing on the FEECA dockets. As directed by Statute, FDACS participated in this proceeding as one of the parties. During the hearing, the PSC heard testimony from all parties in the docket on each issue. The parties filed their Post-Hearing Briefs in September. In its post-hearing brief, FDACS stated that the PSC should continue to balance the goals of energy efficiency and conservation with the impact of the associated costs on all customers, thereby ensuring that all customers benefit from utility-sponsored programs. A diverse, least-cost strategy should be employed to ensure that sound principles of energy efficiency and conservation measures are achieved. The major points made in FDACS' brief were:

- The state can encourage the development of energy efficiency and conservation programs separate from implementing utility-sponsored programs;
- Changes to Florida's building codes requiring homes to be more energy efficient have resulted in significant gains in energy efficiency over the last decade;
- Florida should continue to identify ways to educate customers and provide them with the information and resources needed to pursue energy efficiency and conservation;
- In an effort to balance the equity of the costs and benefits, programs may need to be designed and targeted to capture the needs of low-income customers while eliminating free riders from higher income groups; and
- Based on results of the five year solar pilot programs, the solar pilot programs have not been cost-effective and have created a large cross-subsidy from the general body of ratepayers to a small number of wealthy customers who could afford to invest in solar photo voltaic systems.

On November 25, 2014, the PSC voted to establish goals for the FEECA Utilities based upon a cost-effectiveness analysis that allows all ratepayers, participants and non-participants, to benefit from the utilities' demand-side management programs. The PSC set the utilities' annual goals based upon the Rate Impact Measure (RIM) test to be equal to their achievable potential. While the PSC took the Participant Test and the Total Resource Cost test into consideration, they found that the RIM test allows for a larger amount of cost-effective demand-side management with more potential participants while minimizing cross-subsidization.

In addition, the PSC voted to continue the utilities' solar energy programs until December 31, 2015 and to hold a workshop in 2015 to examine the issues related to solar in Florida including the true cost of solar, existing barriers, and appropriately setting the net metering rate.

The 2015 demand-side management goals approved by the PSC are lower than they have been in previous years even though the PSC is using the same determination methodology. This is a direct result of the current market conditions which are outside the control of the utilities. The cost-effectiveness of demand-side management measures has declined due to several factors, including declining customer usage, new federal appliance efficiency standards (i.e., ENERGY STAR), efficiency improvements in state building codes, and a decline in the price of natural gas. Each of these factors is contributing to the goal of FEECA set by the Florida Legislature, which was to reduce Florida's peak electric demand and energy consumption.

Now that the PSC has set the FEECA goals, the utilities will submit for PSC approval, cost-effective demand-side management (DSM) plans designed to meet those goals. The proposal and approval of the plans will occur in subsequent dockets during 2015. All costs incurred by utilities to implement the FEECA required demand-side management plans are recovered from their customers through a line item on the customers' bills.

Attachment A of this report provides the Executive Summary of the PSC's annual FEECA report. The report details the energy efficiency and conservation efforts by Florida's utilities.

2.4 Transportation Energy

Florida's large population, evolving demographics and projected growth, require the state to develop and maintain a reliable and conveniently accessible transportation system. In addition, Florida's tourism industry is one of the largest contributors to the state's economy, and a progressive and diversified transportation system is vital to the tourist industry.

Florida's Transportation Infrastructure

Florida is unique compared to other states in that it consists of a 447-mile long peninsula, which extends from the Georgia border south to the Florida Keys, a northern panhandle that stretches over 360 miles from the Atlantic to Alabama and nearly 1,200 miles of shoreline, totaling 54,157 square land miles. Within Florida is a strategic system of public roads and highways, maintained by Florida's Department of Transportation (FDOT) and the United States Department of Transportation (USDOT). According to the USDOT's Bureau of Transportation Statistics, Florida has 121,829 miles of public roads, 1,495 miles of interstate, 2,902 miles of railroad tracks used for freight transport, 12,070 road bridges, 1,540 miles of inland waterways, and 129 public use airports.

Petroleum Use

Florida's transportation sector accounts for more than one third of the total energy used in the state, with nearly all transportation fuel being imported. The USDOE Office of Energy Efficiency and Renewable Energy (EERE) states that Florida's per capita energy consumption of motor gasoline was 425 gallons in 2011. This is 15 gallons less than the state consumed in 2010. The US EIA's State Energy Data System (SEDS) reports that Florida consumed more than 7.2 billion gallons of motor fuel and more than 790 million gallons of ethanol in 2012, as highlighted in Figure 9.

In the most recent data reported in 2011 by the US EIA, Florida has a total of 5,839 motor gasoline stations, accounting for 5.3 percent of the total U.S. share. While Florida does not have any in-state refineries to process crude oil, the Florida Department of Environmental Protection, Bureau of Mining and Minerals Regulation, states that Florida produced 2,023,454 barrels of crude oil in 2011, with the majority of it coming from Jay Field in Escambia County.

Figure 9: Annual Motor Gasoline and Fuel Ethanol Consumption (in million gallons)

Source: US EIA

<u>Natural Gas</u>

In addition to becoming Florida's dominant fuel source of choice for electric generation, natural gas is also growing in popularity in the transportation sector. This low-cost transportation fuel has given fleet vehicle owners an alternative fuel choice, resulting in lower fuel and maintenance costs, as compared with diesel fuel. According to the US EIA's Annual Energy Outlook for 2014, natural gas consumption is expected to grow as a fuel source from 25.6 trillion cubic feet (Tcf) in 2012 to 31.6 Tcf in 2040. Although it is considered a dominant fuel source, Florida's heavy reliance on natural gas is a concern for policy makers as it places the state in a scenario where it is susceptible to price volatility and fuel availability.

<u>Florida's Alternative Transportation Use</u>

A number of Florida's private commercial fleet owners, as well as local governments and school boards, have begun the process of converting their fleets to natural gas in order to realize cost savings. There is a growing interest in using propane, compressed natural gas (CNG), and liquefied natural gas (LNG), for large vehicles, and commercial operators. Also, governments have looked into the economic feasibility and are converting their fleets. According to the USDOE Alternative Fuels Data Center, the state of Florida has 758 total public and private alternative fuel stations, and of that amount, 42 are CNG stations, and 62 are propane stations. The state of Florida also has a rebate program for the purchase, lease or conversion of fleet vehicles to natural gas.

Electric vehicles (EV) are also an emerging alternative transportation energy source, especially as technological advancements increase and range anxiety is reduced. Consumers, as well as private businesses and local governments, have been making the investment in electric vehicles as well as the infrastructure to support the charging of these vehicles. The USDOE Alternative Fuels Data Center also states that there are a total of 572 public and private charging stations installed throughout the state.

Florida also has three USDOE designated Clean Cities Coalitions' (CCCs), Southeast Florida, Central Florida, and the state's newest Tampa Bay. The CCCs are responsible for promoting clean energy and alternative fuels for transportation throughout the state. They are tasked with working with vehicle fleets, fuel providers, community leaders, and other stakeholders to reduce Florida's dependence on petroleum use.

2.5 New Trends

Florida is home to more than 19 million residents, with expectations for this number to increase in the future. Changes to Florida's demographic and population profile will affect Florida's demand for stable and reliable energy sources over the next 10 years. The University of Florida's Bureau of Economic and Business Research predicts that by 2040, Florida's population will grow to 25,603,577 people, which can impact the way energy is consumed in the state. Florida also expects to realize a wave of technological advancements in the coming future; while such advancements are typically correlated with higher energy efficiency, more electronics will be used per-capita. Collectively, these factors are expected to yield an exponential increase in energy consumption in the future.

The following technologies are expected to have a significant effect on Florida's energy sector:

<u>Solar Energy</u>
The USDOE's National Renewable Energy Laboratory (NREL) published an article in October 2014 discussing how the price of distributed solar photovoltaic (PV) system prices dropped by 19-20 percent nationwide in 2013. The USDOE's 2012 Renewable Energy Data Book suggests that "solar electricity generating capacity grew by a factor of over 21 between 2000 and 2012, and currently accounts for 0.3 percent of annual U.S. electricity generation." In addition, "30 MW of new concentrating solar power (CSP) capacity came online in the United States in 2012. Solar power generation is also expected to grow in Florida. Florida expects to see an increase in its solar power generation with 332 MW of solar power generating capacity to be installed by 2023.

<u>Electric Vehicles</u>
As technological advancements are made in the battery industry, adoption of electric vehicles continues to grow. The PSC stated in its *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities* that electric vehicles are "anticipated to grow rapidly throughout the planning period resulting in almost a half-million electric vehicles operating within the electric service territories by the end of 2023." The PSC also estimates that Floridians can realize potential gasoline savings of 480 gallons per year by switching to an EV that runs purely on electric power. There are also programs growing in the state to promote the adoption of electric vehicles. The USDOE's Clean Cities Coalitions have been working together to promote the widespread adoption of electric vehicles by means of driver education programs, collaboration with business owners to offer financial incentives for their employees and with customers who drive electric.

<u>Ocean Energy</u>
As noted in past reports, the state of Florida is well positioned to take advantage of the Gulf Stream as a base load renewable energy resource. This resource has an estimated potential to provide 4 to 10 gigawatts of capacity. In 2014, Florida saw a major step forward in harnessing this source of energy as the Florida Atlantic University (FAU) was provided a lease by the Bureau of Ocean Energy Management (BOEM) to begin testing small scale turbines. FAU already has several companies interested in testing turbine at their facility and many of these companies expect commercial viability

before 2020. In addition, the first Florida Renewable Energy Task Force was held by BOEM on December 11, 2014, to begin establishing a regulatory process to deal with these types of issues. The regulatory framework is the major determining factor in regards to the proliferation of these types of technologies.

3. 2014 Accomplishments

The FDACS OOE had an active year administering renewable energy tax incentives, natural gas fleet vehicle conversion rebates, initiating an ENERGY STAR and Water Sense Sales Tax Holiday and working with the Florida Legislature to lower commercial electric taxes to name just a few programs. The following section describes the programs FDACS OOE administered in 2014.

3.1 Florida Renewable Energy Tax Incentives

The Florida Renewable Energy Tax Incentives consists of three available tax incentives and represents a total of $89 million in potential tax credits or sales tax refunds over the life of the program. The three Florida Renewable Energy Tax Incentives include:

1) The *Florida Renewable Energy Technologies Sales Tax Refund,* which provides $1 million per fiscal year for a refund of previously paid Florida sales tax for eligible expenditures,
2) The *Florida Renewable Energy Technologies Investment Tax Credit,* which provides $10 million per fiscal year for an annual corporate tax credit equal to 75 percent of all eligible costs made in connection with the production, storage and distribution of biodiesel, ethanol and other renewable fuel; and
3) The *Florida Renewable Energy Production Credit,* which provided $5 million for the first fiscal year of the program and $10 million for subsequent years for an annual corporate tax credit equal to $0.01/kWh of renewable electricity produced.

The intended goals of the programs are to increase renewable energy production within the state and create new jobs for Floridians.

FDACS estimates that in 2014, a total investment of nearly $24 million for the Renewable Energy Tax Incentives produced an estimated total economic contribution of more than $261.9 million. Further, an estimated total of 909 jobs were created or supported statewide as a result of these incentives. These programs were also responsible for raising an estimated $21.7 million in state and local taxes and generating an estimated $56 million in labor income.

Full reports on the utilization and economic contribution of the Florida Renewable Energy Tax Incentives are available on the FDACS website: http://www.freshfromflorida.com/Energy/Reports-Publications.

3.2 Natural Gas Fuel Fleet Vehicle Rebate Program

Chapter 377.810 Florida Statutes authorized the creation of the Natural Gas Fuel Fleet Vehicle Rebate Program. The FDACS OOE is responsible for administering the program. The program is appropriated $6 million annually for the next five years for the purpose of incentivizing fleets to purchase, lease or convert to natural gas fueled vehicles.

The program took effect on July 1, 2013, and FDACS OOE began rule development on July 2, 2013. Three public workshops were held during the rule development, two in Tallahassee and one in Orlando. The proposed rule was released on October 21, 2013. On January 7, 2014, the rules implementing the Florida Fuel Fleet Vehicle Rebate became effective and the department began accepting applications.

The first year of the program ran on a six-month timeframe from January 7, through June 30, 2014. Though the first year of the rebate program was abbreviated, the FDACS OOE received 572 applications.

The annual assessment of the program found that, even in a shortened first year, the program incentivized an investment of approximately $79.3 million. The assessment also estimated that a total of 382 jobs paying an average of $49,682 a year were created or retained as a result of the program. Additionally, the program's contribution to Florida's Gross Domestic Product was estimated at $127.9 million.

During the first program year, 272 of the 572 received applications were approved and funded for a total rebate expenditure of $3,871,603.34.

The full report is available on the FDACS website: http://www.freshfromflorida.com/Energy/Reports-Publications.

3.3 Florida Energy Systems Consortium Research Developments

The Florida Energy Systems Consortium (FESC) was created in 2008 and is unique in the United States; no other state has a statewide energy consortium involving all of its public universities. The concept combines all of the state's university resources into one statewide center to advance energy research, technology transfer/commercialization, energy education and outreach in this rapidly changing and critically important field.

FESC has been integral in the success of many energy related initiatives. For example, FESC research into hydrogen fuel cells at Florida State University (FSU) led to the creation of Bing Energy, Inc., in Tallahassee. Nine companies were formed with the University of Florida technology, which was developed, in part, with FESC funds and a total 19 companies were created throughout the FESC university system. Also, the USDOE designated Florida Atlantic University (FAU) as a national center for ocean energy research and development which was recently granted the first lease in the Atlantic Ocean to conduct ocean energy research. FAU's facility already has several out-of-state companies interested in utilizing their facility for testing purposes.

Looking forward, FESC would like to capitalize on past successes by utilizing each university's individual strengths. For example, the University of Central Florida is focusing on electric vehicles and charging infrastructure, wireless charging and Photovoltaic; FSU has hired 11 faculty with research expertise in light harvesting materials, polymer characterization, multi-scale material modeling and thermal transport; the University of South Florida will focus on testing a pilot scale thermal energy storage system in collaboration with an electric utility in Florida and developing a novel catalysts for converting carbon dioxide to fuels using solar energy; and FAU is looking to develop a second facility that will be able to support large-scale testing and include transmission capabilities.

3.4 Commercial Sales Tax Decrease and Public Education Capital Outlay (PECO) Increase

HB 5601 was passed in 2014 by the Florida Legislature, which included a reduction in the electricity consumption tax on commercial businesses by 0.05 percent. Commercial businesses include large stores, restaurants, hotels and small "Mom & Pop shops". Further, it transferred the use of 2.6 percent of the remaining tax revenues to support the Public Education Capital Outlay and Debt Service Trust

Fund (PECO). PECO is the sole funding source for the development of Florida's kindergarten through 12th grade education infrastructure (schools, administrative buildings, education infrastructure improvements, etc.) and prior to this allocation did not have a sustainable source of funding. This reduction of sales and use taxes on commercial electric consumption of electricity will benefit commercial businesses in Florida by reducing their overall utility bill. By shifting a large portion of the remaining commercial electric consumption sales and use tax revenue to PECO, it will provide a sustainable revenue stream for local school boards to use in building new schools or making improvements on existing education facilities.

3.5 ENERGY STAR and WaterSense Sales Tax Holiday

Also within HB 5601, the Florida Legislature initiated the first ever Florida ENERGY STAR and WaterSense Sales Tax Holiday on the purchase of energy saving and water saving appliances and fixtures. The sales tax holiday applied to the first $1,500 of specified ENERGY STAR and WaterSense products for the three day period beginning Friday September 19, 2014, through Sunday September 21, 2014. Customers were limited to one purchase of each specific type of ENERGY STAR or Water Sense product with a sales price of $500 or more. ENERGY STAR certified products designated for the purposes of the tax exemption are products approved by the United States Environmental Protection Agency (USEPA) that are affixed with an ENERGY STAR label, including air conditioners, air purifiers, ceiling fans, clothes washers, clothes dryers, dehumidifiers, dishwashers, freezers, refrigerators, water heaters and packages of light bulbs. WaterSense certified products for purposes of the tax exemption are products approved by USEPA that are affixed with a WaterSense label, including bathroom sink faucets, faucet accessories, high-efficiency toilets, showerheads and weather or sensor-based irrigation controllers.

The ENERGY STAR and WaterSense sales tax holiday provided a financial incentive to consumers to invest in ENERGY STAR and Water Sense products. Through the purchase of these products, consumers realized a reduction in the appliance or product price and once home they will save energy, water, and money each month on their utility bills. Florida's first sales tax holiday weekend on ENERGY STAR and WaterSense products proved a success. This program not only helped customers save an estimated $1.6 million at the check-out counter, but will also save them energy, water and money on their bills over the long-term. Retailers reported large increases in sales over the previous year and provided positive feedback about the initiative. Through the Florida Retail Federation, several retailers provided high level sales information indicating the sales tax holiday was a success. One major retailer, for example, reported $1 million in increased sales, and indicated that many customers took advantage of the sales tax holiday to purchase whole ENERGY STAR appliance packages. Another major retailer reported huge increases year over year (comparing sales during the sales tax holiday weekend to the same weekend the previous year) in sales for dishwashers (456%), laundry appliances (423%) and refrigerators (373%). The retailer also stated that WaterSense products showed a significant increase year over year of 25% increase for faucets, 36% increase for high efficiency toilets and 22% increase for showerheads.

3.6 Grant Activities

One of the functions of the FDACS OOE has been to develop, award and manage various state and federal grant programs. From February 2009 to July 2012, the primary focus of the FDACS OOE was the disbursement of American Recovery and Reinvestment Act (ARRA) funds. The state of Florida received approximately $176 million in federal stimulus funds, which were distributed to 150 individual sub-grantees for energy efficiency and renewable energy projects. As of December 31, 2014, the grant is closed.

The ARRA grant provided the seed money to fund the Florida Multi-family Energy Retrofits program in perpetuity. The FDACS OOE will continue to manage that grant, with the Florida Housing Finance Corporation, for the operation of the $8.3 million Multi-family Energy Retrofit Program (MERP) revolving loan fund. This program provides low-interest loans to multi-family housing owners for energy efficiency improvements.

The FDACS OOE is also responsible for administering the state funded Farm to Fuel and Renewable Energy and Energy Efficient Technologies (REET) grant programs. The Farm to Fuel program currently funds six grants with Florida universities for bio-fuel research and development. The REET matching grant program is currently accepting applications for research, development and commercialization projects for renewable energy and energy efficient technologies.

Under a federal cooperative agreement with the US EIA, the FDACS OOE collects propane price information on a weekly basis, based on a sample provided by US EIA. Data for the State Heating Oil and Propane Program (SHOPP) is collected from October through March and assists the US EIA in tracking residential propane prices (http://www.eia.gov/petroleum/heatingoilpropane/). Prices are aggregated for the state, so price data for individual propane dealers remains confidential.

FDACS OOE allocated $1.1 million from the USDOE and created the Energy Efficient Retrofits for Public Facilities grant program, under Title III, Energy Policy and Conservation Act. The program provides funds to local governments and nonprofit organizations to implement energy efficiency projects in public buildings. The competitive grant opportunity was announced in October 2014 and closed in November 2014. FDACS OOE received 25 applications, and those that will be funded must complete work on their projects by July 31, 2015.

3.7 Energy Clearinghouse of Information

FDACS OOE continues to host and expand the Florida Energy Clearinghouse in accordance with Section 570.0741, Florida Statutes. The Florida Energy Clearinghouse provides Floridians the information they need to be knowledgeable energy consumers and make more informed decisions about the energy choices they make every day. Through the online platform, users can compare energy saving technologies, learn more about renewable energy technologies, browse research being conducted at Florida's universities and learn more about energy usage and production.

A major component of the clearinghouse is the "My Florida Home Energy" tool that identifies energy efficient products, services and potential energy and monetary savings for a Florida homeowner based on information provided by the homeowner, as well as publicly accessible data. By educating Floridians on wise energy use, this tool has the potential to improve the quality of their life, both financially and environmentally. The Florida Energy Clearinghouse can be found at: http://www.freshfromflorida.com/Energy/Florida-Energy-Clearinghouse.

3.8 Multifamily Energy and Water Efficiency Study

Multifamily housing accounts for a significant share of energy and water consumption and represents an important segment of the market for efficiency retrofits, yet this market is difficult to penetrate and capture at scale. While the costs of investment in multifamily buildings' energy efficiency typically fall on the shoulders of the property owners/landlords, the stream of benefits from such improvements (primarily in the form of reduced utility bills) typically accrue to the tenants, resulting in a pervasive "split incentive" challenge.

In light of recent reports projecting vast energy and water savings potential and financial returns from multifamily retrofits, the FDACS OOE initiated a study to identify multifamily housing incentives specific to Florida. The multifamily efficiency study is expected to be completed in January 2015. The project team conducting the study includes personnel from the University of Florida (UF) Public Utility Research Center (PURC), who will focus on policy analysis, the UF Program for Resource Efficient Communities (PREC), who will focus on program analysis, and the University of Central Florida's (UCF) Florida Solar Energy Center (FSEC), who will focus on analysis of codes and modeled savings potential.

The goal of this study is to collect and synthesize information from existing literature, industry stakeholders and thought leaders to identify the most promising options for Florida to provide incentives to landlords to retrofit their multifamily properties, saving energy and water and reducing the utility cost burdens on tenants.

3.9 Response to Environmental Protection Agency's Clean Power Plan

In addition to the programs administered on the state level, the FDACS OOE has been following various federal actions and evaluating their potential impacts on Florida. On June 2, 2014, the U.S. Environmental Protection Agency (EPA) proposed updates to 111(d) of the Clean Air Act, also known as the Clean Power Plan (CPP). After a thorough evaluation of the CPP and its potential impacts on Florida, Commissioner Putnam submitted comments expressing his concerns, which include: 1) the EPA's overreach far beyond its jurisdiction in proposing this rule and 2) the failure to fully estimate the economic hardship that will result should these requirements be implemented.

In his letter, Commissioner Putnam urged the EPA to consider the following recommendations before advancing its proposed plan:

- Give states flexibility to determine goals and plans that are in the best interest of their constituents.
- Acknowledge each state's definition for renewable energy is unique to them based on the resources available to them within their borders and include these generation sources for compliance.
- Recognize each state's existing initiatives and programs that can count toward their offsets, such as electric vehicle incentives and energy efficiency requirements.
- Allow additional time required to create and implement plans to avoid disruption to supply and limit the exorbitant costs imposed on consumers.

4. On the Horizon

In 2015, FDACS OOE will continue to work with the Legislature and Governor to advance policies and programs with the objective to secure a stable, reliable and diverse supply of energy for Florida. FDACS OOE is currently developing two new programs to help Florida's farmers adopt practices to increase energy and water efficiency. Those programs are:

Farm Renewable and Efficiency Demonstrations (FRED) Program
In September 2014, the FDACS OOE received a $1 million Conservation Innovation Grant from the United States Department of Agriculture, Natural Resources Conservation Service (USDA-NRCS). Matched by $2 million from the Farm to Fuel program, these funds will be used to establish the Farm Renewable and Efficiency Demonstrations (FRED) program, an innovative program to promote the adoption of technologies and practices that increase energy efficiency and renewable energy use in Florida agriculture.

Direct energy use represents approximately $375 million annually, or 6.5% of Floridian farm production expenses. Each objective and phase of FRED has been designed to address one or more market barriers identified by the FDACS OOE as hindering adoption of energy efficiency and renewable energy technologies in the agriculture industry.

Farm Energy & Water Efficiency Realization (FEWER) Program
Over the past year, Farm to Fuel funds that have been returned to the FDACS OOE are being re-obligated to assist farmers in implementing energy and water efficiencies. The objective of the program is to conduct on-site evaluations of the potential for energy efficiency, renewable energy upgrades and water saving measures and practices on individual farms and help protect water resources and reduce energy consumption. In order to achieve this objective, FDACS will contract with the Suwannee County Conservation District (Contractor) to contract with one or more of the USDA-NRCS Technical Service Providers to conduct on-site evaluations. In addition, they will contract with one or more procured entities to engineer, design, and implement the energy efficiency measures identified in the on-site evaluation report. The Contractor will provide administrative services for this project, including project-funding administration.

Attachment A

Executive Summary of the Florida Public Service Commission's Energy Efficiency and Conservation Act (FEECA) Report

The entire report as prepared by the Florida Public Service Commission, Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act, can be found at: http://www.floridapsc.com/publications/pdf/electricgas/FEECA2015.pdf

Reducing Florida's peak electric demand and energy consumption became a statutory objective in 1980, when the Florida Energy Efficiency and Conservation Act (FEECA) was enacted. Codified in Sections 366.80 through 366.85 and Section 403.519, Florida Statutes (F.S.), FEECA emphasizes reducing the growth rates of weather-sensitive peak demand, reducing and controlling the growth rates of electricity consumption, and reducing the consumption of scarce resources, such as petroleum fuels. Section 366.82(2), F.S., requires the Public Service Commission (Commission or PSC) to set appropriate goals for the seven electric utilities subject to FEECA at least every five years. Commission rules have defined goals with respect to annual electric peak demand and energy savings over a ten-year period, with a review every five years. The seven utilities currently subject to FEECA are Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF), Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Public Utilities Company (FPUC), Orlando Utilities Commission (OUC), and JEA. Once goals are established, the utilities must submit for Commission approval, cost-effective demand-side management (DSM) plans, which contain the DSM programs designed to meet these goals.

This report fulfills two Commission statutory obligations. The Commission is required by Section 366.82(10), F.S., to provide an annual report to the Legislature and the Governor summarizing the adopted goals and progress achieved toward those goals. Section 377.703(2)(f), F.S., requires the Commission to file information on electricity and natural gas energy conservation programs with the Department of Agriculture and Consumer Services.

Section 1 of this report provides a history of FEECA, highlights savings produced by utility programs since 1980, and provides a description of existing tools for increasing conservation throughout the state. Section 2 discusses current goals and achievements of the FEECA utilities. For context, Section 3 provides an overview of Florida's electricity market. Section 4 discusses methods the Commission has used to educate consumers about conservation and provides a list of related web sites. Finally, Appendix 1 provides a description of the conservation programs currently offered by the FEECA utilities.

Conservation Achievements

Over the last thirty-three years, the FEECA utilities' DSM programs in total have reduced winter peak demand by an estimated 6,506 megawatts (MW) and summer peak demand by an estimated 6,871 MW. The demand savings from these programs have resulted in the deferral or avoidance of a substantial fleet of power plants. These programs have also reduced total electric energy consumption by an estimated 9,330 gigawatt-hours (GWh).

Since 1981, Florida's investor-owned electric utilities have recovered over $6 billion of conservation expenditures for DSM programs through the Energy Conservation Cost Recovery (ECCR) clause. Over $3 billion of the total conservation program expenditures recovered have occurred in the last ten years. In 2013, Florida's investor-owned electric utilities recovered over $435 million in conservation program expenditures, performed more than 197,000 residential audits, and offered over 100 conservation programs for residential and commercial customers.

Consumer choice plays an important role in reducing the growth rates of electrical demand and energy in Florida. Consumers support electric energy conservation through a variety of actions including constructing smaller, more efficient homes, buying energy-efficient appliances, installing energy-efficiency upgrades to existing homes and installing demand-side renewable systems. The Commission's consumer education program offers several tools to promote consumer awareness of conservation and energy efficiency opportunities. Florida's utilities also play an active role in educating Florida's consumers on energy efficiency options.

Conversely, prescriptive mandates play a major role in conservation. The Florida Building Code is adopted and updated with new editions triennially by the Florida Building Commission. In addition, the Florida Building Code is amended annually to incorporate interpretations, clarifications and update standards. The 2014 draft of the building code emphasizes the thermal envelope of buildings. Specifically, the energy efficiency section of the code focuses on insulation and ventilation measures for air conditioning units, turn-on/turn-off switches for water heaters and pool heaters, and automatic temperature controls for hot water systems. The U.S. Environmental Protection Agency (EPA) is taking steps to boost clothes dryer efficiency. The EPA announced that beginning in 2015, the manufacturers will be able to use the Energy Star label on clothes dryers that use 20 percent less energy than the minimum efficiency standard. The EPA stated that if all residential clothes dryers in the U.S. meet the requirements, the utility cost savings will grow to more than $1.5 billion per year. In addition, more than 22 billion pounds of greenhouse gas emissions would be prevented.

In 2013, the U.S. Department of Energy (DOE) issued an update for the energy conservation standards for residential microwave ovens which could reduce energy consumption by up to 75 percent in standby mode and revised energy conservation standards for residential room air conditioners. The DOE also initiated rulemaking to amend testing procedures for residential refrigerators and freezers to account for ice-making energy use and to update energy use for other features. Once finalized, the new standards for Energy Star certified refrigerators and freezers would use approximately 10 percent less energy than models meeting the current 2014 standards. Lighting standards have changed as well, with various watts of incandescent bulbs being phased out and becoming no longer available for purchase. Seventy-five watt incandescent bulbs were phased out as of January 1, 2013, and as of January 1, 2014, 60 watt and 40 watt incandescent bulbs are no longer available.

Section 2 of this report compares the FEECA utilities' demand and energy savings to the goals set by the Commission during the last goal–setting proceeding. The results of the 2013 achievements towards the 2009 goals illustrated that TECO, Gulf, JEA, and OUC surpassed all demand and energy savings goals in every category. FPL, DEF, and FPUC did not meet goals in every category in 2013. Of the utilities that did not achieve their annual Commission approved goals, most noted that while they failed to meet the goal requirements on an annual level, they were able to meet the requirements on a cumulative level when compared to the 2004 and 2009 goal proceeding requirements.

Section 2 also provides a summary of the Commission's most recent goal-setting proceeding. On November 25, 2014, the Commission voted to approve staff's recommendation regarding the FEECA utilities' proposed goals for the 2015 through 2024 period. The Commission voted to approve goals based on the Ratepayer Impact Measure (RIM) Test, noting that FPL's approved goals would be based on the unconstrained RIM test.[2] The RIM test is a cost-effectiveness analysis that ensures that all ratepayers, both participants and non-participants, benefit from utility-sponsored conservation programs and minimizes cross subsidies between customers. Utilities were also directed to show how all customers, including low-income customers will be made aware of conservation opportunities. The near term impact will lower the dollars for conservation currently being recovered from customers. In addition, the Commission voted to discontinue the investor-owned utilities' (IOU) solar pilot programs by the end of 2015. The Commission based its decision on evidence in the record that the existing solar pilot programs have not proven to be cost-effective and represented a subsidy between the general body of ratepayers and the few that participated in the program. The Commission also directed its staff to hold a workshop to explore more cost-effective ways to encourage solar adoption in Florida.

Conclusion

The potential demand and energy savings from utility-sponsored conservation programs are affected by consumer education and behavior, building codes, and appliance efficiency standards. Consumer actions to implement energy efficiency measures outside of utility programs as well as codes and efficiency standards, create a baseline for a new program's cost-effectiveness and reduce the amount of incremental energy savings available from utility programs. Utility programs are designed to encourage actions to conserve energy that exceeds the level of conservation resulting from current building codes and minimum efficiency standards. It should be noted that the level of savings from these programs are somewhat uncertain because they depend on voluntary participation from customers. However, the expense is shared by all customers. As such, customer participation, as well as customer education regarding utility-offered DSM and energy conservation programs, along with individual efforts to use electrical energy wisely, remain fundamental elements for reducing the demand for energy.

Conservation and renewable energy are expected to continue to play an important role in Florida's energy future. The Commission will continue its efforts to encourage cost-effective conservation and renewable energy to reduce the use of fossil fuels and defer the need for new generating capacity to ensure a balanced mix of resources that reliably and cost-effectively meet the needs of Florida's ratepayers.

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[2] See Order No. PSC-14-0696-FOF-GU, issued December 16, 2014, in Docket Nos. 130199 through 130205, In re: Commission review of numeric goals (Florida Power & Light Company, Duke Energy Florida, Inc., Tampa Electric Company, Gulf Power Company, JEA, Orlando Utilities Commission, Florida Public Utilities Company).

Office of Energy

Analysis of the Economic Contribution of the Renewable Energy Tax Incentives

2014

Updated February 13, 2015

Florida Department of Agriculture and Consumer Services

Adam H. Putnam, Commissioner

Dear Governor Scott, President Gardiner and Speaker Crisafulli,

Pursuant to Section 377.703(2)(n), Florida Statutes , I am pleased to provide you with the attached Analysis of the Economic Contribution of the 2014 Renewable Energy Tax Incentives. This analysis is a critical assessment of the Renewable Energy Tax Incentives programs, including the Florida Renewable Energy Technologies Investment Tax Credit, the Florida Renewable Energy Production Credit and the Florida Renewable Energy Technologies Sales Tax Refund.

These tax incentives were designed to assist companies to expand renewable energy production within our state and create new jobs for Floridians. As you know, these tax incentives are not energy subsidies like the federal grants or loans that have been plagued with problems. Rather, they are incentives that are available to businesses that demonstrate they are making investments to diversify our state's energy portfolio.

I support and embrace your commitment to ensure that any investment of taxpayer dollars should benefit Florida. To that end, this analysis measures the return on investment of taxpayer dollars in these programs and evaluates whether the programs achieved their intended goals.

Based on the information gathered by the department from applicants, the overall economic contribution these programs have provided our state is substantial. The department estimates that a total investment of nearly $24 million for the Renewable Energy Tax Incentives produced an estimated total economic contribution of more than $261.9 million. Further, an estimated total of 909 jobs were created or supported statewide as a result of these incentives. These programs were also responsible for raising an estimated $21.7 million in state and local taxes and generating an estimated $56 million in labor income.

I hope you find this analysis informative. We look forward to continuing to work with you in order to create a stable, reliable and diverse supply of energy for Florida's future.

Sincerely,

Adam H. Putnam
Commissioner of Agriculture

Table of Contents

1. Introduction

The 2012, the Florida Legislature reinstated the Renewable Energy Tax Incentives as a component of Florida's energy policy. The program consists of three possible tax incentives and represents a total of $89 million in potential tax credits or sales tax refunds during the life of the program. The intended goals of the program are to increase renewable energy production within the state and create new jobs for Floridians.

This report, required by Section 377.703(2)(n), Florida Statutes, is an overview of the utilization of the Renewable Energy Tax Incentives granted this year, as well as a critical assessment to determine if the programs produced a positive economic impact on our state and created new jobs for Floridians.

Through its rules, the Florida Department of Agriculture and Consumer Services (FDACS) required that all applicants provide a description of the economic impact that the eligible project has had on the state. This information may include the total dollar value of additional investment made, the number of jobs created and the total dollar value of salaries and wages of jobs created as a result of the project. Regional economic modeling was used as the basis for this evaluation. FDACS also reviewed public response to the programs, including requests for technical assistance in completing 2015 applications.

2. Florida Renewable Energy Technologies Sales Tax Refund

Pursuant to Section 212.08(7)(hhh), Florida Statutes, the Florida Renewable Energy Technologies Sales Tax Refund Program provides a refund of previously paid Florida sales tax on materials used in the distribution, including fueling infrastructure, transportation and storage, of biodiesel (B10-B100), ethanol (E10-E100) and other renewable fuels. An eligible item is subject to a one-time refund and must be purchased between July 1, 2012, and June 30, 2016. This program is limited to $1 million in Florida sales tax refunds each state fiscal year for all taxpayer applicants.

2.1 Utilization Summary

At the end of the program's first year, Fiscal Year 2012-2013, no refunds were issued as part of the Florida Renewable Technologies Sales Tax Refund. Given the lack of interest demonstrated from prospective participants, the department recommended repealing the program. However, utilization of the Florida Renewable Energy Technologies Sales Tax Refund Program increased in the second year, signaling an increase in interest from prospective participants. During Fiscal Year 2013-2014, FDACS approved $261,686.16 in refunds to eligible applicants.

Given the increased utilization demonstrated in the second year of this program and the positive economic impact generated, as shown in Section 2.3, FDACS supports the continuation of the Florida Renewable Energy Technologies Sales Tax Refund Program.

FDACS will aim to further increase participation in the program by educating eligible businesses on program requirements and providing assistance during the application process. FDACS will also continue to monitor the program and carefully evaluate its impact to ensure that the investments made in this program result in a positive, measurable contribution to Florida's economy.

Table 1. Utilization of the Florida Renewable Energy Technologies Sales Tax Refund

Fiscal Year	Appropriation	Total Refunds Approved	Unused Refunds
FY2012-2013	$1 million	$0	$1 million
FY2013-2014	$1 million	$261,686.16	$738,131.84

FDACS received seven applications under the Florida Renewable Energy Technologies Sales Tax Refund Program in Fiscal Year 2013-2014. Four of the seven applications were approved, totaling $261,686.16. The three applicants whose submissions were deemed incomplete received a full description of their application's deficiencies. Examples of the deficiencies include lack of supporting documentation in the form of invoices and proof of payments, sales tax calculated above the Florida sales tax rate of 6 percent, and failure to provide legible copies of invoices. The rule administering this program allows applicants to submit a corrected application. At this time, the applicants that were determined incomplete have not submitted corrected applications.

Table 2. FY2013-14 Approved Applicant List

Taxpayer	Approved Refund	Fueling Infrastructure	Transportation	Storage
Affordable Bio Feedstock, Inc.	$40,806.76	$40,806.76	$0	$0
Affordable Bio Feedstock of Port Charlotte, LLC	$73,919.40	$73,919.40	$0	$0
Florida Biodiesel Fuel, Inc.	$73,710	$0	$0	$73,710
Affordable Bio Feedstock of Daytona, LLC	$73,250	$0	$0	$73,250
Total	**$261,686.16**	**$114,726.16**	**$0**	**$146,960**

2.2 Methodology

The Renewable Energy Technologies Sales Tax Refund is awarded to eligible applicants as a reimbursement of state sales taxes paid on materials used in the distribution of biodiesel, ethanol, and other renewable fuels. These materials include those used to build, repair, or maintain fueling infrastructure, transportation, and storage facilities for renewable fuels in Florida. However, the total expenditures on renewable fuel distribution supported by this program are much larger than the refunds awarded, since the refunds represent just a small fraction of the total costs of these improvements. Specifically, the refunds amount to just 6% of the total expenditures in materials destined for renewable fuel distribution in the state.

To determine the contribution that the program has made to Florida's economy, a model of the state's economy was created using the IMPLAN regional economic modeling system (Minnesota Implan Group, Inc., 2013) and associated state database for 2011. The use of a regional economic model allows a descriptive analysis that tracks the gross economic activity created by the policy as the dollars cycle through the region's economy (Watson et al., 2007). IMPLAN databases incorporate federal and state economic statistics on commodity production, household and government final demand, industry output, employment, labor and property income, domestic and international trade, personal and business taxes, transfer payments, capital investment, and business inventories. The model estimates regional economic multiplier effects, including direct changes in output or employment, indirect effects on supply chain activity and induced effects on employee household and government spending (Hodges & Spreen, 2012).

At a sales tax rate of 6%, the $261,686.16 in tax refunds supported total equipment purchases for renewable fuel distribution of $4,361,436. Broken down by spending category, $114,726.16 was awarded for purchases in fueling infrastructure materials of $1,904,942, while $146,960 was awarded for purchases in fuel storage materials of $2,449,333.33. Purchases of fueling infrastructure materials generally include items like pumps, piping, tubing and connectors, and therefore are entered into the IMPLAN model in the "fabricated pipe and pipe fitting manufacturing" sector. Similarly, purchases of fuel storage materials are likely to be large metal tanks, metal pipes, and other metallic structures, hence they were entered into the IMPLAN model in the "Metal tanks (heavy gauge) manufacturing" sector, which manufactures tanks, vessels and other containers by cutting, forming and joining heavy-gauge metals, as well as installs heavy-gauge metal tanks (IBIS World, 2014).

2.3 Results

Estimated direct, indirect, induced and total economic contributions of this program are summarized in Table 3. During the 2013-2014 fiscal year, sales tax refunds for renewable fuel distribution capital improvements of $261,686.16 resulted in total purchases of new equipment above $4.3 million and a total economic contribution more than $7.7 million. These refunds also supported or created a total of 42 jobs with an average annual pay of $52,798, for a total income contribution of $2.2 million.

Table 3. Summary of Economic Impacts in 2014 for Renewable Energy Technologies Sales Tax Refund

Impact Type	Employment	Labor Income	Value Added	Output
Direct Effect	18.8	$1,134,865	$1,412,867	$4,354,275
Indirect Effect	10.7	$548,231	$896,082	$1,775,090
Induced Effect	12.5	$534,440	$964,494	$1,627,905
Total Effect	41.9	$2,217,536	$3,273,442	$7,757,270

Estimated local, state and federal taxes collected as a result of the economic activity supported by the program are summarized in Table 4. Total state and local taxes collected were estimated to be $172,121, while total federal taxes collected were estimated to be $450,265.

Table 4. Tax Impacts from the Renewable Energy Technologies Sales Tax Refund

Description	Employee Compensation	Proprietor Income	Tax on Production and Imports	Households	Corporations
Total State and Local Tax	$1,666	$0	$159,660	$7,610	$3,185
Total Federal Tax	$211,175	$8,001	$18,518	$156,342	$56,229

2.4 Additional Jobs Created

As part of the application process, businesses seeking the Renewable Energy Technologies Sales Tax Refund are required to submit a statement of the economic impact created by their investment. As part of their economic impact statement, all approved applicants reported the number of people they expect to employ at their facilities once these facilities become fully operational and are running at full capacity. All of the applicants were able to expand their facilities as a result of the tax credit and have created new positions at their facilities. Across the state, approved applicants expect to employ 170 people once their facilities are operating at or near full capacity.

Table 5. Self-reported Number of Employees Expected at Full Operational Capacity by Businesses Approved for the Renewable Energy Technologies Sales Tax Refund in FY 2013-2014

Taxpayer	Reported Number of Jobs
Affordable Bio Feedstock, Inc.	120
Affordable Bio Feedstock of Port Charlotte, LLC	25
Florida Biodiesel Fuel Inc.	10
Affordable Bio Feedstock of Daytona, LLC	15
Total	**170**

2.5 Applicant Highlights

This section highlights one of the four applicants from the 2014 approved applications to provide a better understanding of the economic contribution these projects have on the state.

Affordable Bio Feedstock, Inc.

Affordable Bio Feedstock, Inc., (ABF) is a family-owned and operated business located in Kissimmee, Florida, that recycles brown grease for use as biodiesel feedstock. Brown grease is cooking oil recovered from a waste water plumbing component that has been contaminated with rotted food solids and considered unsuitable for re-use in most applications. Brown grease is commonly treated with lime and taken to a landfill. However, ABF uses a process called "thermal depolymerization" to transform the brown grease into a source of feedstock to produce biodiesel, organic compost and reclaimed water. During the last six years, ABF has recycled more than 50 million gallons of brown grease, creating more than 3 million gallons of brown grease feedstock and more than 10,000 tons of organic compost, and reclaiming more than 44.5 million gallons of water.

Since starting their business in 2008, ABF has created 120 jobs and invested more than $5.6 million in their Kissimmee plant, $2.5 million of which was invested in the last two years. According to owner Bill Freeman, reinstating the tax incentives allowed ABF to expand their existing plants and add an additional plant in Kissimmee and a new plant in Daytona. ABF is continuing to improve their plants efficiency as well as looking at additional markets in the northern part of the state for expansion.

3. Renewable Energy Technologies Investment Tax Credit

Pursuant to Section 220.192, Florida Statutes, the Renewable Energy Technologies Investment Tax Credit Program provides an annual corporate tax credit equal to 75 percent of all capital costs, operation and maintenance costs, and research and development costs in connection with an investment in the production, storage and distribution of biodiesel (B10-B100), ethanol (E10-E100) and other renewable fuel in the state. Eligible costs must be incurred between July 1, 2012, and June 30, 2016. This program allows $1 million per state fiscal year for each taxpayer with a limit of $10 million per state fiscal year.

3.1 Utilization Summary

FDACS received 19 applications under the Renewable Energy Technologies Investment Tax Credit Program in Fiscal Year 2013-2014. Eleven applications were approved under Fiscal Year 2013-2014, totaling $10,000,000. One of the 11 approved applications was granted a partial credit as funding was exhausted. The rule administering this program allows approved applicants to remain in the first-come, first-served line for the next fiscal year of the program if funds are exhausted.

Seven applications, including the applicant who received a partial credit, did not receive a full credit under Fiscal Year 2013-2014 due to exhaustion of funds. These seven applications totaling more than $6.6 million will receive a credit under Fiscal Year 2014-2015. Two of the 19 applications were not eligible for a tax credit as they had previously received a credit under Fiscal Year 2013-2014. Table 6 below shows the approved credit, broken down by capital costs, operation and maintenance costs, and research and development costs.

Table 6. Utilization of the Renewable Energy Technologies Investment Tax Credit

Fiscal Year	Appropriation	Capital Costs	Operation and Maintenance Costs	Research and Development Costs	Approved Credit
FY2012-13	$10,000,000	$6,418,643.43	$2,007,596.33	$799,414.46	$6,878,263.96
FY2013-14	$10,000,000	$7,004,389.39	$2,944,440	$3,724,689.04	$10,000,000

Table 7. FY2013-14 Approved Applicant List

Taxpayer	Capital Costs	Operation and Maintenance Costs	Research and Development Costs	Total Eligible Costs	Approved Credit
Treasure Coast Biodiesel Feedstock Supply, LLC	$0	$0	$1,402,928.60	$1,402,928.60	$1,000,000
Viesel Fuel, LLC	$1,228,102.76	$68,724.68	$41,972.14	$1,338,799.58	$1,000,000
Affordable Bio Feedstock, Inc.	$669,605.56	$368,173.87	$270,905.35	$1,308,684.78	$981,513.59
FL Biofuels, LLC	$37,732.72	$1,450,460.70	$0	$1,488,193.42	$1,000,000
Affordable Bio Feedstock of Port Charlotte, LLC	$1,302,260	$42,557.92	$0	$1,344,817.92	$1,000,000
Florida Biodiesel Fuel Inc.	$1,302,260	$0	$0	$1,302,260	$976,965
GGS Fort Myers	$68,020.71	$688,885.26	$638,025.50	$1,394,931.47	$1,000,000
Green Energy Advisors Group, LLC	$0	$0	$1,370,857.45	$1,370,857.45	$1,000,000
Green Gallon Solutions of North America, LLC	$623,711.27	$325,637.57	$0	$949,348.84	$712,011.63
Affordable Bio Feedstock of Daytona, LLC	$1,333,350	$0	$0	$1,333,350	$1,000,000
GGS Miami, LLC*	$439,346.37	$0	$0	$439,346.37	$329,509.78
Total	**$7,004,389.39**	**$2,944,440**	**$3,724,689.04**	**$13,673,518.43**	**$10,000,000**

*GGS Miami, LLC received a partial credit under Fiscal Year 2013-2014 due to exhaustion of funding.

All the applicants who received an investment tax credit are continuing to expand or enhance their operations and are expected to submit another application in 2015. In addition, FDACS has answered technical questions about the application process to companies who are in the process of either expanding their operations to Florida, or who are moving their entire operations to Florida in order to take advantage of the tax incentives. It is expected that the demand for this program will continue to grow.

3.2 Methodology

Applicants to the Renewable Energy Technologies Investment Tax Credit were required to provide the capital costs, operation and maintenance costs, and research and development costs incurred in connection with an investment in the production, storage and distribution of renewable fuels for transportation in the state. The sum of these costs represents the investment in renewable fuels production that was directly supported by the program.

A total of $7,004,389.39 of capital improvement costs were claimed by applicants to the program. These expenses were entered into the IMPLAN model in the "Construction of other new nonresidential structures", which includes construction of facilities such as blast furnaces, petroleum refineries, chemical manufacturing plants, power plants and tank storage facilities. Similarly, applicants claimed $2,944,440 in operation and maintenance costs and $3,724,689.04 in research and development costs. These expenses were entered into the IMPLAN model in the "Other basic organic chemical manufacturing" sector, which includes manufacturing of organic fuel propellants and is commonly used to model the biofuels sector (Swenson & Eathington, 2006; Schlosser et al., 2008).

3.3 Results

Estimated direct, indirect, induced and total economic contributions of the program are summarized in Table 8. For Fiscal Year 2013-2014, a total program investment of $10 million produced an estimated total output contribution of $23.6 million, total value added contribution of $9.6 million and total labor income contribution of $6.9 million. Similarly, the program is estimated to have supported or created nearly 70 jobs in the construction and organic chemical manufacturing sectors, as well as 70 jobs in related and supporting industries, thereby having a total estimated employment contribution of 140 jobs.

Table 8. Summary of Economic Impacts in 2014 for Renewable Energy Technologies Investment Tax Credit

Impact Type	Employment	Labor Income	Value Added	Output
Direct Effect	69.7	$3,600,516	$4,074,306	$13,673,518
Indirect Effect	31	$1,655,485	$2,527,145	$4,955,345
Induced Effect	38.9	$1,661,209	$2,997,682	$5,059,960
Total Effect	139.6	$6,917,210	$9,599,134	$23,688,823

Estimated local, state, and federal taxes collected as a result of the economic activity fostered by the program are summarized in Table 9. Total state and local taxes collected were estimated to be $547,179, while total federal taxes collected were estimated to be $1.3 million.

Table 9. Tax Impacts from the Renewable Energy Technologies Investment Tax Credit

Description	Employee Compensation	Proprietor Income	Tax on Production and Imports	Households	Corporations
Total State and Local Tax	$4,873	$0	$510,809	$23,835	$7,662
Total Federal Tax	$617,692	$40,583	$59,247	$489,695	$135,289

3.4 Additional Jobs Created

As part of the application process, businesses seeking the Renewable Energy Technologies Investment Tax Credit are required to submit a statement of the economic impact created by their investment. As part of their economic impact statement, all approved applicants reported the number of people they expect to employ at their facilities once these facilities become fully operational and are running at full capacity. Many of the applicants were able to expand their facilities as a result of the tax credit and have created new positions at their facilities. Across the state, approved applicants expect to employ 371 people once their facilities are operating at or near full capacity.

Table 10. Self-reported Number of Employees Expected at Full Operational Capacity by Businesses Approved for the Renewable Energy Technologies Investment Tax Credit in FY 2013-2014.

Taxpayer	Reported Number of Jobs
Treasure Coast Biodiesel Feedstock Supply, LLC	12
Viesel Fuel, LLC	55
Affordable Bio Feedstock, Inc.	120
FL Biofuels, LLC	16
Affordable Bio Feedstock of Port Charlotte, LLC	25
Florida Biodiesel Fuel Inc.	10
GGS Fort Myers	20
Green Energy Advisors Group, LLC	3
Green Gallon Solutions of North America, LLC	70
Affordable Bio Feedstock of Daytona, LLC	15
GGS Miami, LLC	25
Total	**371**

3.5 Applicant Highlights

This section highlights two of the applicants from the 2014 approved applications to provide a better understanding of the economic contribution these projects have on the state.

Green Gallon Solutions of North America, LLC

Green Gallon Solutions of North America, LLC (GGSNA) is located in Fort Myers, Florida, and is the largest producer of biodiesel in Southwest Florida. GGSNA is a growing Florida business that recycles used cooking oil into a biodegradable, non-toxic fuel which can be used directly in vehicles or blended with petroleum diesel. Since 2012, when the company was founded, GGSNA has invested more than $14 million to build and manage their operations.

GGSNA currently produces nearly 8 million gallons of biodiesel a year and employs 40 full time positions ranging from plant operator to advanced degree positions in executive management, research and development, engineering and operations management. GGSNA has used their Renewable Energy Technologies Investment Tax Credit to expand their existing facilities in North Fort Myers by constructing facilities in Miami and Orlando. With the help of their tax credit, GGSNA is increasing their production capability to 12 million gallons per year and expanding their workforce to 70 full time positions.

Treasure Coast Biodiesel Feedstock Supply, LLC

Treasure Coast Biodiesel Feedstock Supply, LLC (Treasure Coast Biodiesel) is a Florida research and development company based in Stuart, Florida. Since their inception in 2013, Treasure Coast Biodiesel has invested well more than $2.3 million to create a world-class laboratory and hired 15 employees with multiple and advanced degrees to develop alternative feedstocks for use in biodiesel produced by a unique enzymatic process. This enzymatic process requires less energy compared to traditional biodiesel production, and the enzyme process allows the use of a variety of inexpensive, high free fatty acid feedstocks that traditional biodiesel plants are unable to handle. The results of their work have been highlighted in various seminars, tradeshows and industry publications including Biodiesel Magazine.

Treasure Coast Biodiesel is using their approved Renewable Energy Technologies Investment Tax Credit to expand their research facility and continue to identify alternative feedstocks that are not only viable, but less expensive than traditional feedstocks. Treasure Coast Biodiesel expects the use of biodiesel produced by an enzymatic process to not only grow in the state, but throughout the country as well. As this new technology is accepted, Treasure Coast Biodiesel will be able to double their workforce and become a model for testing and research in biodiesel production.

4. Florida Renewable Energy Production Credit

Pursuant to Section 220.193, Florida Statutes, the Florida Renewable Energy Production Credit Program provides an annual corporate tax credit equal to $0.01/kWh of electricity produced and sold by the taxpayer to an unrelated party during a given tax year. The credit may be claimed for electricity produced and sold on or after January 1, 2013, through June 30, 2016.

4.1 Utilization Summary and Public Response

FDACS approved 15 applications totaling $13,773,587.53 for the production period beginning January 1, 2014, and ending December 31, 2014. Funding under Fiscal Year 2013-2014 and Fiscal Year 2014-2015 was exhausted under the 2014 production period.

Table 11. Florida Renewable Energy Production Credit Program Status

Fiscal Year	Appropriation	Total Credits Approved	Unused Credits
FY2012-13	$5 million	$5 million	$0
FY2013-14	$10 million	$10 million	$0
FY2014-15	$10 million	$10 million	$0

Table 12: 2014 Production Year Approved Applicant List

Taxpayer	Type of Renewable Energy	Total Kilowatt Hours Produced	Facility Operation Date	New/ Expanded Facility	FY 2013-14 Credit	FY 2014-15 Credit	Total Approved Credit
Alliance Dairies	Biomass	7,646,863	12/12/2012	New	$20,950.32	$55,518.31	$76,468.63
Florida Power and Light	Solar	108,997,000	12/10/2010	New	$298,345.24	$790,614.33	$1,088,959.57
Florida Power and Light	Solar	17,551,000	4/15/2010	New	$47,817.06	$126,715.11	$174,532.17
Florida Power and Light	Solar	50,714,000	10/27/2009	New	$138,168.43	$366,146.10	$504,314.53
G2 Energy (Marion) LLC	Biomass	26,625,600	1/9/2009	New	$72,540.47	$192,232.12	$264,772.59
Harvest Power Orlando, LLC	Biomass	14,412,243	12/22/2013	New	$39,485.62	$104,636.81	$144,122.43
International Paper Company	Biomass	342,456,620	9/1/2007	New	$930,777.61	$2,466,558.98	$3,397,336.57
Jacksonville Solar	Solar	21,198,952	9/1/2010	New	$57,755.77	$153,052.68	$210,808.45
Mosaic Fertilizer, LLC	Waste Heat	160,118,250	8/15/2008	New	$436,830.57	$1,157,600.21	$1,594,430.79
Mosaic Fertilizer, LLC	Waste Heat	108,191,400	5/9/2014	New	$296,414.94	$785,499.06	$1,081,914
New Hope Power Company	Biomass	344,158,267	9/1/2006	New	$935,387.30	$2,478,774.63	$3,414,161.94
Rayonier Products	Biomass	118,395,958	12/1/2006	New	$323,806.62	$858,086.96	$1,181,893.58
Tropicana Manufacturing Company	Biomass	11,472,894	1/23/2013	New	$31,432.60	$83,296.34	$114,728.94
WM Renewable Energy	Biomass	27,880,320	5/18/2009	New	$75,958.91	$201,290.97	$277,249.88
WM Renewable Energy	Biomass	24,928,231	5/5/2011	New	$67,916.05	$179,977.41	$247,893.46
TOTAL		**1,384,747,598**			**$3,773,587.53**	**$10,000,000**	**$13,773,587.53**

The Florida Renewable Energy Production Credit Program was oversubscribed under the 2014 production period. FDACS expects all 15 applicants who were approved for the 2014 production period will also submit an application in January 2016 for the 2015 production period. In addition, FDACS is aware of other eligible projects in the state and has also answered technical questions about the production tax credit to businesses interested in building solar plants in

Florida. Based on applications received for the 2013 and 2014 production periods, plus the anticipated increase from other eligible projects, FDACS expects Florida businesses will continue to take full advantage of the tax credits available through this program.

4.2 Methodology

The program supported the production of 1,384,747,598 kilowatt-hours of electricity from renewable sources in the 2014 production period. At a state average price of 10.56 cents per kilowatt-hours during the last 24 months (Energy Information Administration), this amounts to an estimated $146,229,346.35 in revenue from the sale of electricity. This estimate of total revenues from sales of renewable electricity supported by the program was entered into the IMPLAN model in the “Electric power generation, transmission, and distribution” sector, which includes establishments that perform one or more of the following activities: operate generation facilities that produce electric energy; operate transmission systems that convey the electricity from the generation facility to the distribution system; and operate distribution systems that convey electric power received from the generation facility or the transmission system to the final consumer.

4.3 Results

Estimated direct, indirect, induced and total economic contributions of the program are summarized in Table 13. For 2014, a total program investment of $13.7 million produced an estimated total output contribution of $230.5 million, total value added contribution of $128.6 million, and total labor income contribution of $46.9 million. Similarly, the program is estimated to have supported or created nearly 166 jobs in the electricity generation, transmission and distribution sector, as well as 562 jobs in related and supporting industries, thereby having an estimated total employment contribution of 728 jobs.

Table 13. Summary of Economic Impacts in 2014 for the Renewable Energy Production Credit

Impact Type	Employment	Labor Income	Value Added	Output
Direct Effect	166.4	$21,619,100	$87,687,299	$149,220,284
Indirect Effect	301.1	$14,021,908	$22,507,106	$46,666,162
Induced Effect	260.4	$11,310,353	$20,411,415	$34,642,094
Total Effect	727.9	$46,951,361	$130,605,820	$230,528,541

Estimated local, state, and federal taxes collected as a result of the economic activity fostered by the program are summarized in Table 14. Total state and local taxes collected were estimated to be $21 million, while total federal taxes collected were estimated to be $14.2 million.

Table 14. Tax Impacts from the Renewable Energy Production Credit

Description	Employee Compensation	Proprietor Income	Tax on Production and Imports	Households	Corporations
Total State and Local Tax	$35,086	$0	$20,616,068	$161,177	$220,036
Total Federal Tax	$4,447,167	$178,531	$2,391,168	$3,311,368	$3,885,145

4.4 Applicant Highlights

This section highlights two of the 15 applicants from the 2014 approved applications to provide a better understanding of the economic contribution these projects are having on the state.

New Hope Power Company

The New Hope Power Plant is the largest renewable energy facility of its kind in North America and one of the largest in the world. Located in West Palm Beach, the New Hope Power Plant is part of an agro-industrial complex which includes a sugar mill and refinery. Urban wood and vegetable waste along with leftover sugar cane fiber are used to supply renewable electricity to the grid and the sugar processing facilities. During 2014, the New Hope Power Plant generated 344,158 megawatt-hours of renewable electricity, which is enough energy to power 32,000 homes for a year. The New Hope Power Plant also diverted 900,000 tons of wood waste from landfills last year which saved 3.5 million cubic yards of valuable landfill space.

The vast majority of the New Hope Power Plant's operation and maintenance expenses remain in the local economy. During 2014, more than $40 million was spent to procure locally sourced fuel and to operate and maintain the facility. The New Hope Power Plant has a permanent staff of 48 people that include supervisorial and professional positions. A dedicated on-site contractor provides another 45 fulltime positions for operators and mechanics. In addition, the New Hope Power Plant typically spends more than $8 million per year on outside contractors to perform non-routine, specialized and major maintenance. Using these figures, the New Hope Power Plant conducted an analysis to determine the economic benefit of their operations in Florida during 2014 and found their facility generated an estimated $28 million of economic activity in Florida and saved ratepayers more than $12 million.

Harvest Power Orlando

Harvest Power Orlando is the first of its kind in the U.S., converting organic waste, primarily yard trimmings and food scraps, into renewable electricity and natural fertilizers. Located within the Reedy Creek Improvement District, Harvest Power Orlando uses anaerobic digestion, a biological process that relies on trillions of naturally occurring bacteria, to produce renewable electricity. When operating at full capacity, the facility will process more than 120,000 tons of organic materials annually while producing 5.4 megawatts of combined heat and power. During 2014, Harvest Power Orlando generated more than 14,000 megawatt-hours of renewable energy.

Harvest Power Orlando invested more than $30 million dollars to bring their renewable energy facility online. Ten fulltime employees, with an annual salary of $800,000, are responsible for the daily operation of the plant. Harvest Power Orlando has also created new jobs for Floridians in the following industries: trucking, construction, hotel, entertainment, and restaurant. Harvest Power Orlando has attracted many visitors from around the world that are interested in replicating their renewable energy facility. Currently, Harvest Power Orlando has talks underway to create large scale recycling and landfill diversion programs with Miami Dade County, City of Tampa, Port of Tampa, Collier County, City of Pensacola, City of Sunrise, Port Canaveral, University of Miami, and the City of Gainesville.

According to the U.S. Environmental Protection Agency, compostable organic material is the largest and heaviest portion of the overall waste stream in the United States. The majority of organic material is discarded with waste and hauled to landfills. Central Florida businesses feed more than 50 million visitors each year which creates more than 356,000 tons of food waste per year. In its first year of operation, Harvest Power Orlando processed more than 17 million gallons of waste water, 4.5 million gallons of kitchen grease trap grease and more than 25,000 tons of food waste.

5. Return on Investment

To examine the gains that result from the Renewable Energy Tax Incentives to the economy of Florida, FDACS developed a measure of the Return on Investment (ROI) of the policy and associated programs. Two variations of this measure show the economic contributions and tax revenues generated for each dollar that the state invested in the Renewable Energy Technologies Investment Tax Credit, the Renewable Energy Production Credit and the Renewable Energy Tax Incentives as a whole during 2014. The measure is calculated using the following equation:

$$ROI = \frac{Return}{Investment}.$$

In the equation, *Return* refers to either the estimated total economic contribution or state and local taxes collected as a result of the program, while *Investment* refers to the total amount of credits approved by the department. The ROI for each of the two individual programs, and for the policy as a whole, are shown in Table 15.

Table 15. Return on Investment (ROI) from the Renewable Energy Technologies Investment Tax Credit, Renewable Energy Production Credit, and Renewable Energy Tax Incentives Policy

Program	Contribution ROI	State and Local Tax ROI
Renewable Energy Technologies Sales Tax Refund (Program)	$29.64	$0.66
Renewable Energy Technologies Investment Tax Credit (Program)	$2.37	$0.05
Renewable Energy Production Credit (Program)	$16.74	$1.53
Renewable Energy Tax Incentives (Policy)	$10.90	$0.90

Calculation of the ROI from the Renewable Energy Tax Incentives shows that all of these programs provide positive and sizable returns to the state of Florida. Each dollar invested in the Renewable Energy Technologies Sales Tax Refund yields an estimated $29.64 in economic output throughout the state, and an estimated 66 cents of each dollar returns to state and local government coffers in the form of taxes. Similarly, every dollar invested in the Renewable Energy Technologies Investment Tax Credit results in an estimated $2.37 of economic activity throughout the state, and an estimated 5 cents of every dollar returns to state and local government as tax revenues. The Renewable Energy Production Credit has an even more impressive return on investment, as every dollar invested in this program results in an estimated $16.74 of economic activity throughout the state, and an estimated $1.53 returns to state and local government as tax revenues.

Combining the three programs together to measure the ROI of the policy as a whole yields similarly impressive results, as every dollar invested in these incentives results in an estimated $10.90 in economic activity throughout the state, and an estimated 90 cents returns to state and local government in the form of tax revenues.

6. Annual Trends in Program Contribution

The monetary awards and economic contribution of the Renewable Energy Tax Incentives Program have grown significantly in the second fiscal year of program implementation. As shown in Figure 1, every component of the program has experienced increased use of funds, and the program as a whole has experienced an increase in annual disbursements of nearly $5.8 million.

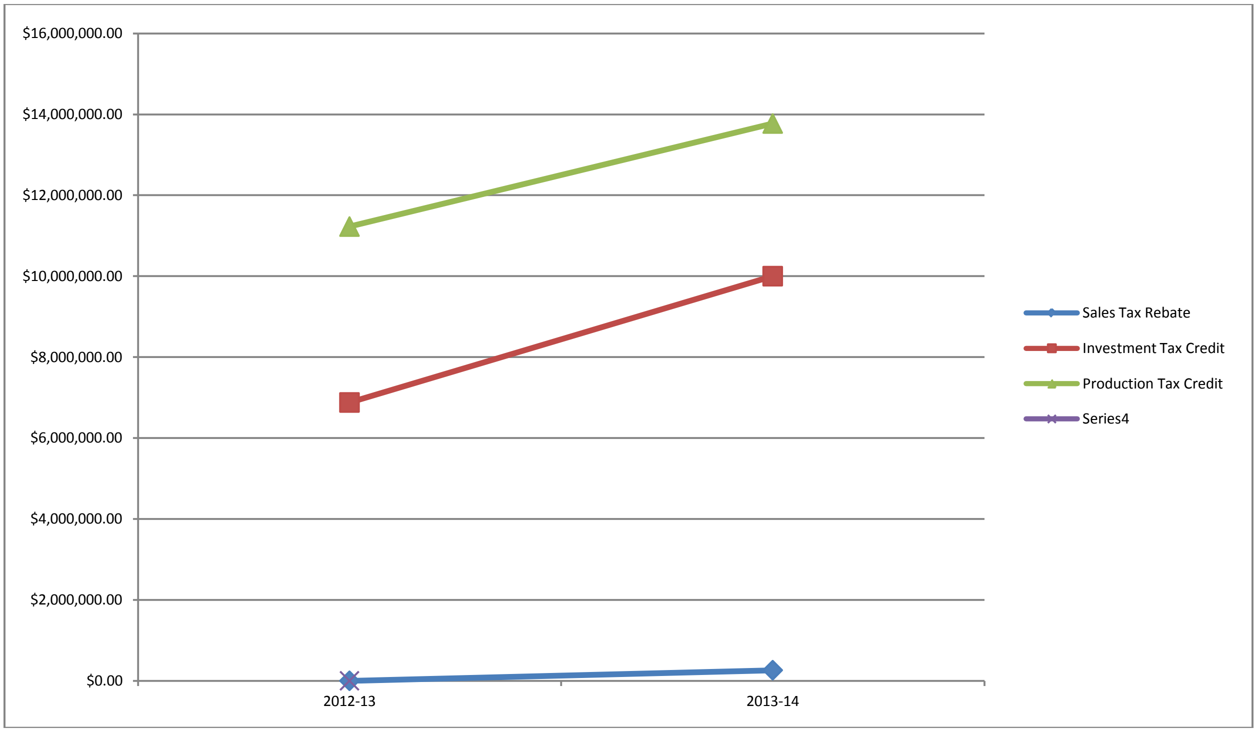

Figure 1. Funds awarded through the Renewable Energy Tax Incentives Program, FY2012-13 – FY2013-14.

Similarly, the economic contribution of the program has risen significantly since in the second year of program implementation. As Figure 2 shows, the economic contribution from every program component has increased in FY2013-14 over its FY2012-13 baseline. Overall, the program's statewide economic contribution has increased by a total of $58 million during FY 2013-14.

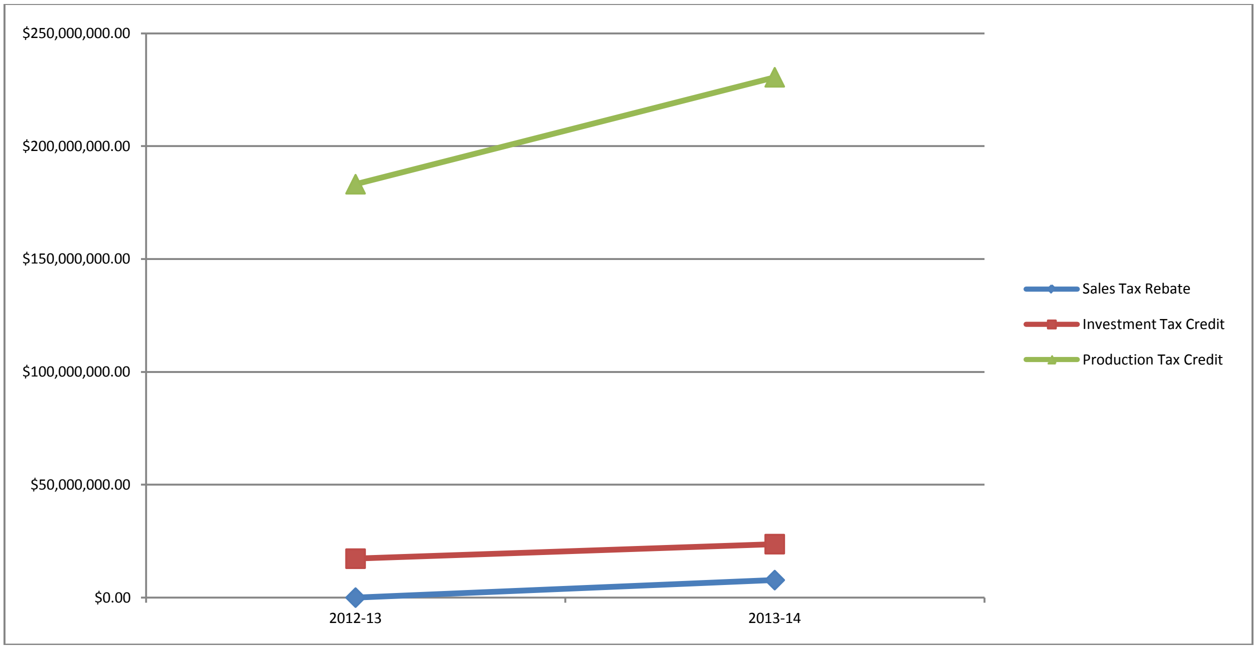

Figure 2. Economic contribution of the Renewable Energy Tax Incentives Program, FY2012-13 – FY2013-14.

7. Conclusion

The economic contribution of the Florida Renewable Energy Tax Incentives has been substantial. In 2014 alone, an investment in these programs of nearly $24 million resulted in an estimated 909 jobs created or supported statewide. Similarly, these programs were responsible for raising an estimated $21.7 million in state and local taxes, generating an estimated $56 million in labor income and producing an estimated total economic contribution of more than $261.9 million.

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COST EFFECTIVENESS MANUAL

FOR

DEMAND SIDE MANAGEMENT PROGRAMS

AND

SELF SERVICE WHEELING PROPOSALS

Florida Public Service Commission

Tallahassee, Florida

Adopted at June 11, 1991 Agenda Conference

Effective: July 17, 1991

TABLE OF CONTENTS

SECTION I. INTRODUCTION

This manual describes the minimum data requirements for the cost-effectiveness analyses used by the Florida Public Service Commission (FPSC) to evaluate utility proposed conservation programs, direct load control programs, and self-service wheeling proposals. The use of this manual is authorized by FPSC Rule 25-17.008, F.A.C.

Chapter 366.82, Florida Statutes, requires the FPSC to review and approve cost effective utility conservation programs. In addition, Chapter 366.051, Florida Statutes, requires public utilities to provide wheeling for self-service customers if such wheeling is not likely to result in higher cost electric service to the utility's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers. FPSC Rule 25-17.008 and this manual were adopted as part of the implementation of these Statutes.

There are three tests contained in this manual: the Total Resource Test, the Participants Test, and the Rate Impact Test. In evaluating conservation and direct load control programs, the Commission will review the results of all three tests to determine cost-effectiveness. The Rate Impact and Total Resource tests used for self-service wheeling projects are similar to those used for conservation and load control programs. A Participants Test is not specified for self-service wheeling since it is assumed that the proposal is cost-effective to the party requesting the wheeling. In addition to the Rate Impact and Total Resource tests, there are additional considerations listed for self-service wheeling projects.

Figure 1 is a pictorial comparison of the three cost effectiveness analyses set forth in this manual. Only very broad categories of costs and benefits are depicted so that the conceptual differences may be seen at a glance. The detailed definitions and applicable formulas are found in the manual proper.

The calculation of demand-reduction benefits for cost-effectiveness analyses performed under FPSC Rule 25-17.008 shall be on a revenue requirements basis for all programs under consideration. However, when the demand reduction achieved by a program cannot be reasonably projected to extend for the life of the avoided generating unit, the demand-reduction benefits shall also be calculated on a value of deferral basis.

The term "avoided generating unit" as used in this manual refers to a utility's proposed generating unit that is avoided in whole or in part by the demand-side management program. Avoided capacity charges shall be used in lieu of avoided generating unit costs, where appropriate, to determine cost effectiveness. Use of avoided capacity charges in lieu of avoided generating unit costs may be particularly appropriate by nongenerating utilities, wholesale power purchasers, or members of a power pool arrangement.

This manual does not address interruptible and curtailable load. However, nothing herein shall preclude the Commission from applying this methodology to such non-firm load after explicit consideration of the matter by the Commission in a proceeding.

The delineation of the various ways of expressing test results is not meant to discourage the continued development of additional variations for expressing cost-effectiveness.

SECTION II. CONSERVATION AND DIRECT LOAD CONTROL

This Section describes the cost effectiveness tests that are required for conservation and direct load control programs. Three separate tests are defined. These are: the Total Resource Test, the Participants Test, and the Rate Impact Test.

The following information is provided for each test: (1) a definition; (2) the components of the benefits; (3) the components of the costs; (4) the formulas to be used to express the results in acceptable ways; and (5) the reporting format.

TOTAL RESOURCE COST TEST

DEFINITION:

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. This test may be turned into a Societal Test by excluding tax credit benefits, by including costs and benefits of externalities, and by using a societal discount rate, assuming that the costs and benefits of externalities are quantifiable.

GENERAL DESCRIPTION OF BENEFITS:

The benefits are the avoided supply costs, including avoided generation, transmission, and distribution costs. The avoided supply costs should be calculated using net savings, i.e., savings net of changes in energy use that would have happened in the absence of the program. Benefits include avoided supply costs for energy-using equipment not chosen by the participant.

GENERAL DESCRIPTION OF COSTS:

The costs are the program costs incurred by the utility and any increased supply costs. All equipment costs, installation, operation and maintenance, and administration costs, no matter who pays for them, are included in this test.

FORMULAS:

B_{npv} = Sum of (B_t / D^{t-1}) for t = 1 to n

C_{npv} = Sum of (C_t / D^{t-1}) for t = 1 to n

where

B_{npv} is the net present value of program benefits
C_{npv} is the net present value of program costs
B_t are the total program benefits for year t
C_t are the total program costs for year t
D is 1 + the discount rate for the utility
n is the life of the program

B_t is further defined as follows:

$B_t = AG_t + AT_t + AD_t + FS_t + TC_t + OB_t$

where

AG_t are the avoided generation benefits
AT_t are the avoided transmission benefits
AD_t are the avoided distribution benefits
FS_t are the fuel savings from decreased sales
TC_t are any tax credits
OB_t are any other quantifiable benefits

AG_t is further defined as follows:

$AG_t = AC_t + AO_t + AF_t - RF_t$

where

AC_t are avoided unit capacity costs
AO_t are avoided unit O&M costs
AF_t are avoided unit fuel costs
RF_t are replacement fuel costs

AC_t may be calculated for either the Value of Deferral or Revenue Requirements Methodology.

For the purpose of the Revenue Requirements Methodology, AC_t is further defined as follows:

AC_t = 0 before the in-service year

AC_t = CC * GPR_t * GKW Red_t

where

CC is the avoided in-service year capacity costs including AFUDC
GPR_t is the revenue requirement in percent of capital cost
GKW Red_t is the number of Kilowatts of plant avoided

where

GPR_t is the Annual Revenue Requirement factor which is calculated on PSC Form CE 1.1A, by taking annual total fixed charges (Column 10) divided by in-service cost.

GKW Red = Cumulative Total Participating Customers x KW Red

Cumulative Total Participating Customers is defined on PSC Form CE 1.2, Input Data -- Part 2, Col (3).

KW Red is defined in Section IV, PSC Cost Effectiveness Forms, PSC Form CE 1.1, Input Data -- Part 1.

AT_t and AD_t, avoided transmission plant and avoided distribution plant, are defined similarly to AC_t. The in-service year, the economic life, and the Revenue Requirement factor for transmission and distribution plant may differ from that of the avoided generating unit.

For the purpose of applying the Value of Deferral Methodology, AC_t is defined as follows:

$AC_t = 0$ before the in-service year

$AC_t = K*CC*(1-R)/(1-R^N)$ for the in-service year

$AC_t = AC_{t-1}*(1+E_p)$ after the in-service year

where

N is the economic life of the avoided generating unit
K is the present value of carrying charges for one dollar of investment over N years
CC is the avoided in-service-year capacity costs including AFUDC
E_p is the plant cost escalation rate

$R = (1+E_p)/D$

AT_t and AD_t, avoided transmission plant and avoided distribution plant, are defined similarly to AC_t. The in-service year, the economic life, K factor, and plant escalation rate for transmission and distribution plant may differ from that of the avoided generating unit.

C_t is further defined as follows:

$C_t = IS_t + UC_t + PC_t + OC_t$

where

IS_t are any increased supply costs
UC_t are utility program costs
PC_t are participant program costs
OC_t are other quantifiable costs

If $B_{npv} > C_{npv}$ the program is cost effective.

<u>REPORTING FORMAT</u>:

Input: PSC Forms CE 1.1, 1.1A, 1.1B, 1.2

Output: PSC Forms CE 2.1, 2.2, 2.3

PARTICIPANTS TEST

DEFINITION:

The Participants Test measures the impact of the program on the participating customers.

GENERAL DESCRIPTION OF BENEFITS:

The benefits include the reductions in the customers' bills, incentives paid by the utility or other third party, and any tax credits received. Savings estimates should be based on gross energy savings as opposed to net energy savings. (Net savings are gross savings minus savings that would have occurred even in the absence of the program.)

For fuel substitution programs, benefits include the avoided capital and operating costs of the equipment not chosen. For load building programs, benefits include any increases in productivity or services attributable to the load building program.

GENERAL DESCRIPTION OF COSTS:

The costs include increases in the customers' bills, equipment and materials purchased, ongoing operation and maintenance costs and any equipment removal costs.

FORMULAS:

B_{npv} = Sum of (B_t / D^{t-1}) for t = 1 to n

C_{npv} = Sum of (C_t / D^{t-1}) for t = 1 to n

where

B_{npv} is the net present value of program benefits
C_{npv} is the net present value of program costs
B_t are the total program benefits for year t
C_t are the total program costs for year t
D is 1 + the discount rate for part. customers
n is the life of the program

B_t is further defined as follows:

$$B_t = BS_t + TC_t + UR_t + OB_t$$

where

BS_t are savings in customer bills
TC_t are any tax credits
UR_t are utility rebates or incentives
OB_t are any other quantifiable benefits

C_t is further defined as follows:

$$C_t = EC_t + CM_t + OC_t$$

where

EC_t are customer equipment costs
CM_t are customer O&M costs
OC_t are other quantifiable costs

If $B_{npv} > C_{npv}$ the program is cost effective.

<u>REPORTING FORMAT</u>:

Input: PSC Forms CE 1.1, 1.2

Output: PSC Forms CE 2.4

RATE IMPACT TEST

DEFINITION:

The Rate Impact Test is an indirect measure of the impact on customer rates caused by the program. Rates will go down more than they otherwise would have if the change in utility revenues minus the change in utility costs is positive. Rates will go up more than they otherwise would have if the change in utility revenues minus the change in utility costs is negative.

GENERAL DESCRIPTION OF BENEFITS:

The benefits are the avoided supply costs, including avoided generation, transmission, and distribution costs. The benefits also include any increased revenues generated by the program. Reductions in supply costs and revenue increases should be calculated using net energy savings. (Net savings are gross savings minus savings that would have occurred even in the absence of the program.)

GENERAL DESCRIPTION OF COSTS:

The costs include the program costs incurred by the utility, the incentives paid to participants, and increased supply costs. The costs also include any decrease in revenues caused by the program.

FORMULAS:

B_{npv} = Sum of (B_t / D^{t-1}) for t = 1 to n

C_{npv} = Sum of (C_t / D^{t-1}) for t = 1 to n

where

B_{npv} is the net present value of program benefits
C_{npv} is the net present value of program costs
B_t are the total program benefits for year t
C_t are the total program costs for year t
D is 1 + the discount rate for the utility
n is the life of the program

B_t is further defined as follows:

$$B_t = AG_t + AT_t + AD_t + FS_t + IR_t + OB_t$$

where

AG_t are the avoided generation benefits
AT_t are the avoided transmission benefits
AD_t are the avoided distribution benefits
FS_t are the fuel savings from decreased sales

IR_t are any increased revenues
OB_t are any other quantifiable benefits
AG_t is further defined as follows:

$$AG_t = AC_t + AO_t + AF_t - RF_t$$

where

AC_t are avoided unit capacity costs
AO_t are avoided unit O&M costs
AF_t are avoided unit fuel costs
RF_t are replacement fuel costs

AC_t may be calculated for either the Value of Deferral or Revenue Requirements Methodology.

For the purpose of the Revenue Requirements Methodology, AC_t is further defined as follows:

$$AC_t = 0 \text{ before the in-service year}$$

$$AC_t = CC * GPR_t * GKW\ Red_t$$

where

CC is the avoided in-service year capacity costs including AFUDC
GPR_t is the revenue requirement in percent of capital cost
GKW Red_t is the number of Kilowatts of plant avoided

where

GPR_t is the Annual Revenue Requirement factor which is calculated on PSC Form CE 1.1A, by taking annual total fixed charges (Column 10) divided by in-service cost.

GKW Red = Cumulative Total Participating Customers x KW Red

Cumulative Total Participating Customers is defined on PSC Form CE 1.2, Input Data -- Part 2, Col (3).

KW Red is defined in Section IV, PSC Cost Effectiveness Forms, PSC Form CE 1.1, Input Data -- Part 1.

AT_t and AD_t, avoided transmission plant and avoided distribution plant, are defined similarly to AC_t. The in-service year, the economic life, and the Revenue Requirement factor for transmission and distribution plant may differ from that of the avoided generating unit.

For the purpose of applying the Value of Deferral Methodology, AC_t is defined as follows:

$AC_t = 0$ before the in-service year

$AC_t = K*CC*(1-R)/(1-R^N)$ for the in-service year

$AC_t = AC_{t-1}*(1+E_p)$ after the in-service year

where

N is the economic life of the avoided generating unit
K is the present value of carrying charges for one dollar of investment over N years
CC is the avoided in-service-year capacity costs including AFUDC
E_p is the plant escalation rate
$R = (1+E_p)/D$

AT_t and AD_t, avoided transmission plant and avoided distribution plant, are defined similarly to AC_t. The in-service year, the economic life, K factor, and plant escalation rate for transmission and distribution plant may differ from that of the avoided generating unit.

C_t is further defined as follows:

$C_t = IS_t + LR_t + UC_t + UR_t + OC_t$

where

IS_t are any increased supply costs
LR_t are lost revenues from reduced sales
UC_t are utility program costs
UR_t are utility rebates/incentives for participants.
OC_t are other quantifiable costs

If $B_{npv} > C_{npv}$ the program is cost effective.

<u>REPORTING FORMAT</u>:

Input: PSC Forms CE 1.1, 1.1A, 1.1B, 1.2

Output: PSC Forms CE 2.1, 2.2, 2.5, 2.5S

SECTION III. SELF-SERVICE WHEELING

This Section describes the prescribed cost effectiveness tests for self-service wheeling proposals. The reason for a separate section is that there are costs and benefits unique to cogeneration facilities, such as supplemental and standby purchases.

A self-service wheeling proposal is one where a utility retail customer proposes to generate power at one of its locations and have it delivered to another of its locations through the utility's transmission or distribution system. Chapter 366.051, Florida Statutes, requires public utilities to provide wheeling for self-service customers if such wheeling is not likely to result in higher cost electric service to the utility's general body of retail and wholesale customers.

The Rate Impact and Total Resource tests used here are similar to those used for conservation and load control programs. No Participants Test is specified since it is assumed that the proposal is cost-effective to the party requesting the wheeling. In addition to the Rate Impact and Total Resource tests, there are additional considerations listed for self-service wheeling projects.

RATE IMPACT TEST FOR SELF-SERVICE WHEELING

DEFINITION:

The Rate Impact Test for Self-Service Wheeling is an indirect measure of the impact on customer rates caused by the wheeling proposal. Rates will go down more than they otherwise would have if the change in utility revenues minus the change in utility costs is positive. Rates will go up more than they otherwise would have if the change in utility revenues minus the change in utility costs is negative.

GENERAL DESCRIPTION OF BENEFITS:

The benefits include avoided generation, transmission, and distribution costs, and any increased revenues, such as wheeling revenues and increased standby revenues, generated by the proposed project.

GENERAL DESCRIPTION OF COSTS:

The costs include any decrease in revenues caused by the program and any increased supply costs. When marginal fuel cost is less than average fuel cost, the decrease in sales will cause an increase in average fuel cost that must be borne by the remaining customers. Costs also include loss of fixed plant costs collected through demand or non-fuel energy charges.

FORMULAS:

B_{npv} = Sum of (B_t / D^{t-1}) for t = 1 to n

C_{npv} = Sum of (C_t / D^{t-1}) for t = 1 to n where

B_{npv} is the net present value of benefits
C_{npv} is the net present value of costs
B_t are the total benefits for year t
C_t are the total costs for year t
D is 1 + the discount rate for the utility
n is the life of the program

B_t is further defined as follows:

$$B_t = AG_t + AT_t + AD_t + IR_t + FS_t + OB_t$$

where

AG_t are the avoided generation benefits
AT_t are the avoided transmission benefits
AD_t are the avoided distribution benefits
IR_t are the increased revenues
FS_t are the net fuel savings
OB_t are any other quantifiable benefits

AG_t is further defined as follows:

$$AG_t = AC_t + AO_t + AF_t - RF_t$$

where

AC_t are avoided unit capacity costs
AO_t are avoided unit O&M costs
AF_t are avoided unit fuel costs
RF_t are replacement fuel costs

AC_t may be calculated for either the Value of Deferral or Revenue Requirements Methodology.

For the purpose of the Revenue Requirements Methodology, AC_t is further defined as follows:

$$AC_t = 0 \text{ before the in-service year}$$

$$AC_t = CC * GPR_t * GKW\ Red_t$$

where

CC is the avoided in-service year capacity costs including AFUDC
GPR_t is the revenue requirement in percent of capital cost
GKW Red_t is the number of Kilowatts of plant avoided

where

GPR_t is the Annual Revenue Requirement factor which is calculated on PSC Form CE 1.1A, by taking annual total fixed charges (Column 10) divided by in-service cost.

GKW Red = Cumulative Total Participating Customers x KW Red

Cumulative Total Participating Customers is defined on PSC Form CE 1.2, Input Data -- Part 2, Col (3).

KW Red is defined in Section IV, PSC Cost Effectiveness Forms, PSC Form CE 1.1, Input Data -- Part 1.

AT_t and AD_t, avoided transmission plant and avoided distribution plant, are defined similarly to AC_t. The in-service year, the economic life, and the Revenue Requirement factor for transmission and distribution plant may differ from that of the avoided generating unit.

For the purpose of applying the Value of Deferral Methodology, AC_t is defined as follows:

$AC_t = 0$ before the in-service year

$AC_t = K*CC*(1-R)/(1-R^N)$ for the in-service year

$AC_t = AC_{t-1}*(1+E_p)$ after the in-service year

where

N is the tax life of the avoided generating unit
K is the present value of carrying charges for one dollar of investment over N years
CC is the avoided in-service-year capacity costs including AFUDC
E_p is the plant escalation rate
$R = (1+E_p)/D$

AT_t and AD_t, avoided transmission plant and avoided distribution plant, are defined similarly to AC_t. The in-service year, the economic life, K factor, and plant escalation rate for transmission and distribution plant may differ from that of the avoided generating unit.

C_t is further defined as follows:

$C_t = FC_t + LR_t + OC_t$

where

FC_t are net increase in fuel costs
LR_t are lost revenues from reduced sales
OC_t are other quantifiable costs

If $B_{npv} > C_{npv}$ the program is cost effective.

REPORTING FORMAT:

Input: PSC Forms CE 3.1, 1.1A, 1.1B, 3.2

Output: PSC Forms CE 2.1, 2.2, 3.3, 3.3S

TOTAL RESOURCE TEST FOR SELF-SERVICE WHEELING

DEFINITION:

The Total Resource Cost Test measures the net costs of a self-service wheeling project as a resource option based on the total costs of the project, including both the participants' and the utility's costs. This test may be turned into a Societal Test by excluding tax credit benefits, by including costs and benefits of externalities, and by using a societal discount rate, assuming that the costs and benefits of externalities are quantifiable.

GENERAL DESCRIPTION OF BENEFITS:

The benefits are the avoided supply costs, including avoided generation, transmission, and distribution costs.

GENERAL DESCRIPTION OF COSTS:

The costs are the project costs incurred by the utility and any increased supply costs. All equipment costs, installation, operation and maintenance, and administration costs, no matter who pays for them, are included in this test.

FORMULAS:

B_{npv} = Sum of (B_t / D^{t-1}) for t = 1 to n

C_{npv} = Sum of (C_t / D^{t-1}) for t = 1 to n

where

B_{npv} is the net present value of project benefits
C_{npv} is the net present value of project costs
B_t are the total project benefits for year t
C_t are the total project costs for year t
D is 1 + the discount rate for the utility
n is the life of the project

B_t is further defined as follows:

$$B_t = AG_t + AT_t + AD_t + FS_t + TC_t + OB_t$$

where

AG_t are the avoided generation benefits
AT_t are the avoided transmission benefits
AD_t are the avoided distribution benefits
FS_t are the fuel savings from decreased sales
TC_t are any tax credits
OB_t are any other quantifiable benefits

AG_t is further defined as follows:

$$AG_t = AC_t + AO_t + AF_t - RF_t$$

where

AC_t are avoided unit capacity costs
AO_t are avoided unit O&M costs
AF_t are avoided unit fuel costs
RF_t are replacement fuel costs

AC_t may be calculated for either the Value of Deferral or Revenue Requirements Methodology.

For the purpose of the Revenue Requirements Methodology, AC_t is further defined as follows:

AC_t = 0 before the in-service year

AC_t = CC * GPR_t * GKW Red_t

where

CC is the avoided in-service year capacity costs including AFUDC
GPR_t is the revenue requirement in percent of capital cost
GKW Red_t is the number of Kilowatts of plant avoided

where

GPR_t is the Annual Revenue Requirement factor which is calculated on PSC Form CE 1.1A, by taking annual total fixed charges (Column 10) divided by in-service cost.

GKW Red = Cumulative Total Participating Customers x KW Red

Cumulative Total Participating Customers is defined on PSC Form CE 1.2, Input Data -- Part 2, Col (3).

KW Red is defined in Section IV, PSC Cost Effectiveness Forms, PSC Form CE 1.1, Input Data -- Part 1.

AT_t and AD_t, avoided transmission plant and avoided distribution plant, are defined similarly to AC_t. The in-service year, the economic life, and the Revenue Requirement factor for transmission and distribution plant may differ from that of the avoided generating unit.

For the purpose of applying the Value of Deferral Methodology, AC_t is defined as follows:

AC_t = 0 before the in-service year

$AC_t = K*CC*(1-R)/(1-R^N)$ for the in-service year

$AC_t = AC_{t-1}*(1+E_p)$ after the in-service year

where

N is the economic life of the avoided generating unit
K is the present value of carrying charges for one dollar of investment over N years
CC is the avoided in-service-year capacity costs including AFUDC
E_p is the plant cost escalation rate

$R = (1+E_p)/D$

AT_t and AD_t, avoided transmission plant and avoided distribution plant, are defined similarly to AC_t. The in-service year, the economic life, K factor, and plant escalation rate for transmission and distribution plant may differ from that of the avoided generating unit.

C_t is further defined as follows:

$C_t = IS_t + UC_t + PC_t + OC_t$

where

IS_t are any increased supply costs
UC_t are utility program costs
PC_t are participant program costs
OC_t are other quantifiable costs

If $B_{npv} > C_{npv}$ the project is cost effective.

REPORTING FORMAT:

Input: PSC Forms CE 1.1, 1.1A, 1.1B, 1.2

Output: PSC Forms CE 2.1, 2.2, 2.3

OTHER CONSIDERATIONS

In addition to the Rate Impact and Total Resource tests, the following will be considered by the Commission in its determination of the cost-effectiveness of self-service projects:

(1) The type of fuel used at the cogeneration project.

(2) The fuel efficiency of the project.

(3) The likelihood of a cogenerator building its own transmission line to its other location.

(4) The materiality of any lost revenues indicated by the Rate Impact test.

SECTION IV. FPSC COST EFFECTIVENESS FORMS

This Section contains the forms to be used in conjunction with the tests discussed in the previous sections of this manual. The following list contains the FPSC Form designation, the name of the FPSC Form, and a brief description of each form. This is followed by sample forms to be used, showing column headings and other pertinent information.

<u>PSC FORM CE 1.1</u> Input Data -- Part 1

This form, along with PSC FORM CE 1.2, specifies the input data to be used in the cost-effectiveness test for conservation and direct load control programs. Each element on the form is defined below:

I.(1) <u>Customer KW Reduction at Meter</u>

This is the maximum load reduction in kilowatts at the customer's meter.

I.(2) <u>Generator KW Reduction Per Customer</u>

This input is developed by taking into account such factors as reliability, line losses and customer diversity. A crude, but acceptable, method of calculating the KW reduction is to use the following formula:

$$\text{KW Red}=[DS_w(WLOLP) + DS_s(SLOLP)] / [(ALOLP)(1\text{-}FOR)(1\text{-}DL)]$$

where

DS_w is the demand saving at winter peak
DS_s is the demand saving at summer peak
WLOLP is the winter seasonal LOLP
SLOLP is the summer seasonal LOLP
ALOLP is the annual LOLP
FOR is the forced outage rate
DL is the kw line loss factor

and

$$(WLOLP + SLOLP) / ALOLP = 1$$

I.(3) <u>KW Line Loss Percentage</u>

This is the percentage reduction in KW from the generator to the customer.

I.(4) <u>Generation KWH Reduction Per Customer</u>

This is the annual KWH reduction given by the following formula:

KWH Red = KWH_m / (1 - EL)

where

KWH_m is the KWH reduction at the customer's meter
EL is the energy line loss factor to account for losses from the generator to the customer location

I.(5) KWH Line Loss Percentage

This is the percentage reduction in KWH from the generator to the customer.

I.(6) Group Line Loss Multiplier

This is a factor used to take into account the fact that various groups of customers receive service at different voltage levels. It is used to adjust the fuel cost calculation for participating customers.

I.(7) Customer KWH Increase at Meter

For conservation programs, this input would normally be zero. But, for other programs such as thermal storage, there may be an increase in KWH during off-peak periods.

II.(1) Study Period for the Conservation Program

This is the economic life of the conservation program, and will generally be less than or equal to the life of the unit to be avoided.

II.(2) Generator Economic Life

This is the economic life of the avoided generating unit.

II.(3) Transmission and Distribution Economic Life

This is the economic life of the avoided transmission and distribution facilities.

II.(4) K Factor for Generation

This is the present value of carrying charges for a $1 investment over the life of the generating unit. PSC FORM CE 1.1A must be filed showing in detail the calculation of this factor.

II.(5) K Factor for Transmission and Distribution

This is the present value of carrying charges for a $1 investment over the life of the avoided transmission and distribution facilities. PSC FORM CE 1.1A must be filed showing in detail the calculation of this factor.

III.(1) Utility Nonrecurring Cost per Customer

This represents nonrecurring costs in the base year that would be incurred by the utility, such as a one-time customer rebate.

III.(2) Utility Recurring Cost per Customer

This represents recurring costs in the base year that would be incurred by the utility, such as O&M costs associated with the installed equipment.

III.(3) Utility Cost Escalation Rate

This rate is used to escalate the costs identified in III.(2). Normally, this rate would be close to the rate at which the Consumer Price Index is projected to increase.

NOTE: As an alternative, annual program costs may be specified for each year on the appropriate FORM, but detailed documentation must be attached to show how these costs were computed.

III.(4) Customer Equipment Cost

This is the base year cost for equipment incurred by each customer when the program is selected.

III.(5) Customer Equipment Cost Escalation Rate

This rate is used to escalate the costs identified in III.(4). Normally, this rate would be close to the rate at which the Consumer Price Index is projected to increase.

NOTE: As an alternative, annual customer equipment costs may be specified for each year on the appropriate FORM, but detailed documentation must be attached to show how these costs were computed.

III.(6) Customer O&M Cost

This is the base year cost for O&M incurred by each participating customer.

III.(7) Customer O&M Cost Escalation Rate

This rate is used to escalate the costs identified in III(6). Normally, this rate would be close to the rate at which the Consumer Price Index is projected to increase.

NOTE: As an alternative, annual O&M costs may be specified for each year on the appropriate FORM, but detailed documentation must be attached to show how these costs were computed.

IV.(1) Base Year

This is the reference year for the present worth analyses and the first year for recording costs and benefits of the program.

IV.(2) In-Service Year for Avoided Generator Unit

This is the in-service year of the generating unit to be avoided or deferred by the conservation program.

IV.(3) In-Service Year for Avoided T&D

This is the in-service year of the transmission and distribution facilities to be avoided or deferred by the conservation program.

IV.(4) Base Year Avoided Generating Unit Cost

This is the base year cost in dollars per kilowatt of the generating unit to be avoided or deferred by the conservation program. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the unit in the in-service year, including AFUDC.

IV.(5) Base Year Avoided Transmission Cost

This is the base year cost in dollars per kilowatt of the transmission facilities to be avoided or deferred by the conservation program. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the facilities in the in-service year, including AFUDC.

IV.(6) Base Year Avoided Distribution Cost

This is the base year cost in dollars per kilowatt of the distribution facilities to be avoided or deferred by the conservation program. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the facilities in the in-service year, including AFUDC.

IV.(7) Gen, Tran, and Dist Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in IV.(4) through IV.(6).

IV.(8) Generator Fixed O&M Costs

This is the annual fixed O&M costs for the generating unit to be avoided or deferred, stated in $/KW/Year.

IV.(9) Generator Fixed O&M Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in IV.(8).

IV.(10) Transmission Fixed O&M Costs

This is the annual fixed O&M costs for the transmission facilities to be avoided or deferred, stated in $/KW/Year.

IV.(11) Distribution Fixed O&M Costs

This is the annual fixed O&M costs for the distribution facilities to be avoided or deferred, stated in $/KW/Year.

IV.(12) Trans and Distr Fixed O&M Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in IV.(10) and IV.(11).

IV.(13) Avoided Generating Unit Variable O&M Costs

This is the base year variable O&M costs for the generating unit to be avoided or deferred, stated in cents/KWH.

IV.(14) Generator Variable O&M Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in IV.(13).

IV.(15) Generator Capacity Factor

This is the projected capacity factor of the generating unit to be avoided or deferred.

IV.(16) Avoided Generating Unit Fuel Cost

This is the base year fuel costs for the generating unit to be avoided or deferred, stated in cents/KWH.

IV.(17) Avoided Generating Unit Fuel Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in IV.(16).

V.(1) Non Fuel Cost in Customer Bill

This is the base year non fuel charge in the participating customer's bill in cents per KWH.

V.(2) Non Fuel Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in V.(1).

V.(3) Demand Charge in Customer Bill

This is the base year demand charge in the participating customer's bill in $/KW/Month. This would be zero for residential customers.

V.(4) Demand Charge Escalation Rate

This is the escalation rate to be used in escalating the costs in V.(3).

PSC FORM CE 1.1A Calculation of K Factor

This form specifies the data to be used when calculating the K Factor for the avoided generating unit and also for avoided transmission and distribution plant, if applicable. Each element on the form is defined below:

Col (1) Year

The years begin with the in-service year of the avoided unit (or avoided transmission and distribution plant) and extend through the life of the unit (or other avoided plant).

Col (2) Mid-Year Rate Base

This column contains, for each year, the value of the avoided investment at mid year. This is calculated by averaging the beginning-of-year and end-of-year rate bases. The end-of-year rate base is calculated by subtracting straight-line depreciation (Column 9) and deferred taxes (Column 7) from beginning-of-year rate base. See PSC Form CE 1.1A, Page 2 of 2 for this calculation. The beginning-of-year rate base is the in-service cost of the plant calculated on PSC FORM CE 1.1B.

Col (3) Debt

This column contains, for each year, the cost of debt associated with the investment given in Column (2).

Col (4) Preferred Stock

This column contains, for each year, the after-tax cost of preferred stock associated with the investment given in Column (2).

Col (5) Common Equity

This column contains, for each year, the after-tax cost of common equity associated with the investment given in Column (2).

Col (6) Taxes

This column contains, for each year, the taxes associated with the before-tax cost of preferred and common stock.

Col (7) Other Taxes & Insurance

This column contains all taxes and insurance not contained in Column (6).

Col (8) Depreciation

This column contains, for each year, the depreciation costs associated with the in-service cost of the avoided plant.

Col (9) Deferred Taxes
This column contains the deferred taxes for each year. The tax depreciation schedule is given as Page 2 of 2 of PSC FORM CE 1.1A.

Col (10) Total Fixed Charges

This column contains, for each year, the sum of column (3) through column (8).

Col (11) Present Worth Fixed Charges

This column is the present value of the corresponding numbers in the previous column, using the in-service year as the reference year.

Col (12) Cumulative Present Worth Fixed Charges

This column is the year by year accumulation of the numbers in the previous column.

As indicated in the example, this form must also contain the in-service cost of the plant, the book life of the plant, the capital structure, the effective tax rate, and the discount rate used to calculate present worth dollars.

PSC FORM CE 1.1B Calculation of AFUDC and In-Service Cost of Plant

This form specifies the data to be used when calculating AFUDC and the in-service cost of plant (generating unit or transmission and distribution plant). Each element on the form is defined below:

Col (1) Year

The years begin with the first year of construction for the avoided unit (or avoided transmission and distribution plant) and extend to the in-service year.

Col (2) Years Prior to In-Service Year

This column contains the number of years prior to the in-service year of the plant corresponding to each year in Column (1).

Col (3) Plant Escalation Rate

This column contains the plant escalation rate corresponding to each year in Column (1).

Col (4) Cumulative Escalation Rate

This column contains the cumulative escalation rate corresponding to each year in Column (3).

Col (5) Percent Expenditure

This column contains, for each year of construction, the percentage of the plant to be constructed. The sum of the percentages in this column should equal 100.

Col (6) Annual Spending

This column contains the year-end spending, in dollars per kilowatt, for each year of construction.

Col (7) Cumulative Average Spending

This column contains the cumulative average spending for each year of construction.

Col (8) Cumulative Spending with AFUDC

This column contains, for each year, the cumulative average spending for that year (from Column 7) plus the AFUDC that has accumulated through the previous year.

Col (9) Yearly AFUDC

This column contains the AFUDC applicable for each year.

Col (10) Incremental Year-End Book Value

This column contains the incremental value added to the plant each year.

Col (11) Cumulative Year-End Book Value

This column contains, for each year, the cumulative year-end book value for the plant. The final figure in this column represents the in-service year cost.

As indicated in the example, this form must also contain the in-service cost of the plant (in dollars per kilowatt), the base year construction cost ($/KW), and the AFUDC rate.

PSC FORM CE 1.2   Input Data -- Part 2

This form, along with PSC FORM CE 1.1 specifies the input data to be used in the cost-effectiveness test for conservation and direct load control programs. Each element on the form is defined below:

Col (1) Year

The years begin with the Base Year and extend through the life of the conservation program.

Col (2) Cumulative Total Participating Customers

This column contains, for each year, the cumulative total participating customers without regard as to whether they would have adopted the conservation measure in the absence of a utility sponsored program.

Col (3) Adjusted Cumulative Total Participating Customers

This column contains, for each year, the cumulative total participating customers adjusted for the fact that some customers would have adopted the conservation measure in the absence of a utility sponsored program.

Col (4) Utility Average System Fuel Cost

This column contains, for each year, the annual average system fuel cost, including costs of purchases and sales.

Col (5) Avoided Marginal Fuel Cost

This column contains, for each year, the annual average avoided fuel costs in cents per KWH. These costs should reflect the fact that conservation programs have different impacts on the system, depending on the hour of the day. If the program reduces consumption on peak, the marginal fuel costs may be significantly higher than the average fuel costs, resulting in savings to all customers.

Col (6) Increased Marginal Fuel Cost

This column contains, for each year, the annual average increased fuel costs in cents per KWH. These costs reflect the fact that some conservation programs increase energy use during certain hours.

Col (7) Replacement Fuel Cost of Avoided Generating Unit

This column contains, for each year, the annual average replacement fuel costs in cents per KWH. This is the system fuel cost if the utility had built the unit to be avoided. If the avoided unit would have lowered system fuel costs, then these costs act as an offset to the savings gained by not building the unit. On the other hand, if the avoided unit would have raised system fuel costs, there are additional savings to be achieved by avoiding the unit.

Col (8) Program KW Effectiveness Factor

This column contains, for each year, a factor that represents the degradation or improvement of the demand savings over time. Complete documentation must be supplied if a factor other than 1 is used.

Col (9) Program KWH Effectiveness Factor

This column contains, for each year, a factor that represents the degradation or improvement of the energy savings over time. Complete documentation must be supplied if a factor other than 1 is used.

PSC FORM CE 2.1 Avoided Generating Unit Benefits

This form is used to report the avoided generating unit benefits of a conservation program or self-service wheeling project. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program. Normally, benefits on this form will be zero until the in-service year of the avoided unit. Also, benefits will only accrue for the life of the conservation program.

Col (2) Avoided Generating Unit Capacity Cost

This column contains the avoided generating unit benefits as previously defined in Section II. These are value of deferral benefits that extend from the in-service year of the avoided unit through the life of the conservation program or the life of the avoided unit, whichever comes first.

Col (3) Avoided Generating Unit Fixed O&M

This column contains the avoided generating unit fixed O&M costs. This may be calculated by taking the dollars per kilowatt per year as reported on PSC FORM CE 1.1 times the kilowatts saved, with costs escalated appropriately.

Col (4) Avoided Generating Unit Variable O&M

This column contains the avoided generating unit variable O&M costs. This may be calculated by taking the dollars per kilowatt-hour reported on PSC FORM CE 1.1 times the kilowatts saved times the capacity factor times 8760, with costs escalated appropriately.

Col (5) Avoided Generating Unit Fuel Costs

This column contains the annual fuel costs for the avoided generating unit. This may be calculated by taking the fuel cost reported on PSC FORM CE 1.1 times the kilowatts saved times the capacity factor times 8760, with fuel costs escalated appropriately.

Col (6) Replacement Fuel Costs

This column contains the replacement fuel costs that occur because the avoided generating unit was not built. These costs may be calculated by multiplying the annual kwh generation of the avoided unit by the replacement fuel costs shown on PSC FORM CE 1.2. (The net fuel savings of the avoided plant would be calculated by subtracting this column from column 5). For a base loaded avoided unit, the net fuel savings might be large. At the other extreme, the net fuel savings for a peaker might be very small or slightly negative.

Col (7) Avoided Generating Unit Benefits

This column is the sum of columns (2) through (5) minus column (6).

This form also contains totals for each column and the cumulative net present value for each column.

PSC FORM CE 2.2 Avoided T&D, Program Fuel Savings, and Other Benefits

This form is used to report the avoided transmission benefits, avoided distribution benefits, program fuel savings, and other benefits of a conservation program or self-service wheeling project. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program.

Col (2) Avoided Transmission Capacity Cost

This column contains the avoided transmission capacity benefits as previously defined in Section II. These are value of deferral benefits that extend from the in-service year of the avoided transmission plant through the life of the conservation program or the life of the avoided generating unit, whichever comes first.

Col (3) Avoided Transmission Fixed O&M Cost

This column contains the avoided generating unit fixed O&M costs. This may be calculated by taking the dollars per kilowatt per year as reported on PSC FORM CE 1.1 times the kilowatts saved, with costs escalated appropriately.

Col (4) Total Avoided Transmission Cost

This is the sum of columns (2) and (3).

Col (5) Avoided Distribution Capacity Cost

This column is analogous to Column (2).

Col (6) Avoided Distribution Fixed O&M Cost

This column is analogous to Column (3).

Col (7) Total Avoided Distribution Costs

This is the sum of columns (5) and (6).

Col (8) Program Fuel Savings

This column contains the fuel savings generated by the conservation program. This is the product of the kwh saved per customer, the number of participating customers, and the appropriate marginal fuel cost.

PSC FORM CE 2.3 Total Resource Cost Test

This form is used for the Total Resources Cost Test. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program.

Col (2) Increased Supply Costs

This column contains any increased supply costs associated with the program. This includes both energy and capacity supply costs as well as costs for alternate fuels.

Col (3) Utility Program Costs

This column contains the costs of the program incurred by the utility, including equipment costs, administrative costs.

Col (4) Participant Program Costs

This column is the same as column (10), PSC FORM CE 2.4.

Col (5) Other Costs

This column contains other quantifiable costs attributable to the program, including environmental and other external costs.

Col (6) Total Costs

This column is the sum of the costs in columns (2) through (5).

Col (7) Avoided Generating Unit Benefits

This column is the same as column (7) on PSC FORM 2.1.

Col (8) Avoided Transmission and Distribution Plant Benefits

This column is the sum of columns (4) and (7) on PSC FORM CE 2.2.

Col (9) Program Fuel Savings

This column is the same as column (8) on PSC FORM CE 2.2.

Col (10) Other Benefits

This column contains any other quantifiable benefits. Complete documentation must be provided to support the figures in this column.

Col (11) Total Benefits
This column is the total of columns (7) through (11).

Col (12) Net Benefits

This is total costs minus total benefits.

Col (13) Cumulative Discounted Net Benefits

The figures in this column are obtained by discounting the figures in column (12) to the first year in column (1) and then accumulating these discounted figures year by year.

PSC FORM CE 2.4 Participant Costs and Benefits

This form is used to report the costs and benefits for the participating customers. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program.

Col (2) Savings in Participants' Bills

This column contains the savings in customer bills brought about by the reduction in kwh usage.

Col (3) Tax Credits

This column contains any tax credits received by the participant.

Col (4) Utility Rebates

This column contains any utility rebates to participating customers.

Col (5) Other Benefits

This column contains other quantifiable benefits to the participant attributable to the program. Complete documentation must be provided to support the figures in this column.

Col (6) Total Benefits

This column is the sum of the costs in columns (2) through (5).

Col (7) Customer Equipment Costs

This column contains equipment costs borne by the participating customer.

Col (8) Customer O&M Costs

This column contains O&M costs borne by the participant.

Col (9) Other Costs

This column contains other quantifiable costs borne by the participant. Complete documentation must be provided to support the figures in this column.

Col (10) Total Costs

This column is the total of columns (7) through (9).

Col (11) <u>Net Benefits</u>

The numbers in this column are calculated by subtracting column (9) from column (6).

Col (12) <u>Cumulative Discounted Net Benefits</u>

This column contains the cumulative discounted net benefits of the program. The figures in this column are obtained by discounting the figures in column (11) and accumulating them year by year.

This form also contains the in-service year of the avoided generating unit and the appropriate customer discount rate.

PSC FORM CE 2.5 Rate Impact Test

This form is used to report the costs and benefits from the standpoint of the impact on customer rates. If costs exceed benefits, rates would be higher than they otherwise would be if the program is implemented. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program.

Col (2) Increased Supply Costs

This column is identical to column (2), PSC FORM CE 2.3.

Col (3) Utility Program Costs

This column is identical to column (3), PSC FORM CE 2.3.

Col (4) Incentives

This column contains any utility incentives paid to the participating customers.

Col (5) Revenue Losses

This column contains any revenue losses for periods where the load has been decreased.

Col (6) Other Costs

This column contains any other quantifiable costs attributable to the program. Complete documentation must be provided to support the figures in this column.

Col (7) Total Costs

This column is the sum of columns (2) through (6).

Col (8) Avoided Gen Unit & Fuel Benefits

This column is the sum of columns (4) and (5), PSC FORM CE 2.1.

Col (9) Avoided T&D Benefits

This column is identical to column (8), PSC FORM CE 2.3.

Col (10) Revenue Gains

This column contains any revenue losses for periods where the load has been increased.

Col (11) Other Benefits

This column contains other quantifiable benefits. Complete documentation must be provided for the numbers in this column.

Col (12) Total Benefits

This column is the sum of columns (8) through (11).

Col (13) Net Benefits

This column is calculated by subtracting column (7) from column (12).

Col (14) Cumulative Discounted Net Benefits

This column is the accumulation of the figures in column (13), discounted by the appropriate discount rate.

This form also contains the discount rate and the benefit/cost ratio.

PSC FORM CE 2.5S Supplementary Form on Revenue Gains and Losses

A supplementary form will be filed containing, for each year, an allocation of the revenue gains and losses reported in columns (5) and (10) to general and administrative, generation, transmission and distribution.

PSC FORM CE 3.1 Input Data, Self-Service Wheeling -- Part 1

This form, along with PSC FORM CE 3.2, specifies the input data to be used for self-service wheeling proposals. Each element on the form is defined below:

I.(1) Generator KW Reduction

This input is calculated by taking into account such factors as reliability, line losses and customer diversity.

I.(2) KW Line Loss Percentage

This is the percentage reduction in KW from the generator to the customer.

I.(3) KWH Line Loss Percentage

This is the percentage reduction in KWH from the generator to the customer.

I.(4) Group Line Loss Multiplier

This is a factor used to take into account the fact that various groups of customers receive service at different voltage levels.

II.(1) Study Period for the Proposal

This is the number of years in the analysis and will generally be less than or equal to the life of the avoided unit.

II.(2) Generator Economic Life

This is the economic life of the avoided generating unit.

II.(3) T&D Economic Life

This is the economic life of the avoided transmission and distribution facilities.

II.(4) K Factor for Generation

This is the present value of carrying charges for a $1 investment over the life of the avoided generating unit. PSC FORM CE 1.1A must be filed showing in detail the calculation of this factor.

II.(5) K Factor for T&D

This is the present value of carrying charges for a $1 investment over the life of the avoided transmission and distribution facilities. PSC FORM CE 1.1A must be filed showing in detail the calculation of this factor.

III.(1) Supplemental Billing KW Reduction
The reduction in billing demand for supplemental purchases because the QF

will serve load with its own generation.

III.(2) Supplemental MWH Reduction at Meter

The reduction in energy for supplemental purchases as a result of self-service wheeling.

III.(3) Self-Service Wheeling Charge

The charge for self-service wheeling.

III.(4) Wheeling Escalation Rate

The annual rate of escalation that applies to III.(6).

III.(5) Standby Billing KW Increase

The increase in billing demand for standby purchases as a result of self-service wheeling.

III.(6) Standby MWH Increase at Meter

The increase in billing energy for standby purchases as a result of self-service wheeling.

IV.(1) Utility Non-Recurring Cost

This represents non-recurring costs in the base year of the analysis.

IV.(2) Utility Recurring Costs

These are the recurring administrative costs of the utility as a result of the self-service wheeling proposal.

IV.(3) Utility Cost Escalation Rate

This rate is used to escalate the costs in IV.(2).

V.(1) Base Year

This is the reference year for the present worth analyses and the first year for recording costs and benefits of the proposal.

V.(2) In-Service Year of Avoided Gen Unit

This is the in-service year of the generating unit to be avoided by the self-service wheeling project.

V.(3) In-Service Year for Avoided T&D

This is the in-service year of the transmission and distribution facilities to be avoided by the self-service wheeling project.

V.(4) Base Year Avoided Gen Unit Cost

This is the base year cost in dollars per kilowatt of the generating unit to be avoided or deferred by the project. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the unit in the in-service year, including AFUDC.

V.(5) Base Year Avoided Transmission Cost

This is the base year cost in dollars per kilowatt of the transmission facilities to be avoided or deferred by the project. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the unit in the in-service year, including AFUDC.

V.(6) Base Year Avoided Distribution Cost

This is the base year cost in dollars per kilowatt of the distribution facilities to be avoided or deferred by the project. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the unit in the in-service year, including AFUDC.

V.(7) Gen, Trans, Dist Cost Escalation Rate

This rate is used to escalate the costs in V.(4), V.(5) and V.(6).

V.(8) Generator Fixed O&M Costs

This is the annual fixed O&M costs for the generating unit to be avoided or deferred, stated in $/KW/Year.

V.(9) Generator Fixed O&M Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in V.(8).

V.(10) Transmission Fixed O&M Costs

This is the annual fixed O&M costs for the transmission facilities to be avoided or deferred, stated in $/KW/Year.

V.(11) Distribution Fixed O&M Costs

This is the annual fixed O&M costs for the distribution facilities to be avoided or deferred, stated in $/KW/Year.

V.(12) Trans and Distr Fixed O&M Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in V.(10) and

V.(11).

V.(13) Avoided Generating Unit Variable O&M Costs
This is the base year variable O&M costs for the generating unit to be avoided or deferred, stated in cents/KWH.

V.(14) Generator Variable O&M Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in V.(13).

V.(15) Generator Capacity Factor

This is the projected capacity factor of the generating unit to be avoided or deferred.

V.(16) Avoided Generating Unit Fuel Cost

This is the base year fuel costs for the generating unit to be avoided or deferred, stated in cents/KWH.

V.(17) Avoided Generating Unit Fuel Cost Escalation Rate

The rate of escalation that the cost in V.(16) would be escalated each year.

VI.(1) Supplemental Service Rate, Non-Fuel

The non-fuel energy charge in the QF's bill for supplemental service.

VI.(2) Supplemental Service Rate, Demand

The demand charge in the QF's bill for supplemental service.

VI.(3) Supplemental Service Escalation Rate

The annual rate of escalation that applies to items VI.(1) and VI.(2).

VI.(4) Standby Rate, Non-Fuel

The non-fuel energy charge in the QF's bill for standby service.

VI.(5) Standby Rate, Demand

The demand charge in the QF's bill for standby service.

VI.(6) Standby Escalation Rate

The annual rate of escalation that applies to items VI.(4) and VI.(5).

PSC FORM CE 3.2 Input Data, Self-Service Wheeling -- Part 2

This form, along with PSC FORM CE 3.1, specifies the input data to be used for self-service wheeling proposals. Each element on the form is defined below:

Col (1) Year

The years begin with the base year and extend through the life of the proposal.

Col (2) Utility Average System Fuel Cost

This is the utility's annual system fuel cost approved by the FPSC that includes fuel, purchases and sales.

Col (3) Utility Purchase Marginal Fuel Cost

This is the marginal fuel cost reduction caused by purchases of QF energy by the utility.

Col (4) QF Supplemental Marginal Fuel Cost

This is the marginal fuel cost reduction caused by the reduction in supplemental purchases by a QF that serves its own load.

Col (5) QF Standby Marginal Fuel Cost

This is the marginal fuel cost increase caused by the increase in standby purchases by the QF.

Col (6) Replacement Fuel Cost

This column contains, for each year, the annual average replacement fuel costs in cents per kwh. This is the system fuel cost if the utility had built the unit to be avoided. If the avoided unit would have lowered system fuel costs, then these costs act as an offset to the savings gained by not building the unit. On the other hand, if the avoided unit would have raised system fuel costs, there are additional savings to be achieved by avoiding the unit.

Col (7) QF Effectiveness Factor -- KW

This is a factor that is normally 1.00, but may be reduced or increased to simulate degradation or improvement on KW.

Col (8) QF Effectiveness Factor -- KWH

This is a factor that is normally 1.00, but may be reduced or increased to simulate degradation or improvement on KWH.

PSC FORM CE 3.3 Self Service Wheeling Rate Impact Test

This form is used to report the costs and benefits from the standpoint of the impact on customer rates of a self-service wheeling proposal. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program.

Col (2) Increased Fuel Costs

This column is used to report any increases in fuel costs attributable to the self-service wheeling proposal.

Col (3) Revenue Losses

This column is used to report any revenue losses resulting from the proposal.

Col (4) Other Costs

This column contains any other quantifiable costs. Complete documentation must be provided to support the numbers in this column.

Col (5) Total Costs

This column is the sum of columns (2) through (4).

Col (6) Avoided Gen Unit and Fuel Benefits

This column is the sum of columns (4) and (5), PSC FORM CE 2.1.

Col (7) Avoided T&D Benefits

This column is the sum of columns (4) and (7), PSC FORM CE 2.2.

Col (8) Revenue Gains

This column contains any revenue gains, such as wheeling revenues, resulting from the proposal.

Col (9) Other Benefits

This column contains other quantifiable benefits. Complete documentation must be provided for the numbers in this column.

Col (10) Total Benefits

This column is the sum of columns (7) through (10).

Col (11) Net Benefits

This column is calculated by subtracting column (6) from column (11).

Col (12) Cumulative Discounted Net Benefits

This column is the accumulation of the figures in column (12), discounted by the appropriate discount rate.

This form also contains the discount rate and the benefit/cost ratio.

PSC FORM CE 3.3S Supplementary Form on Revenue Gains and Losses

A supplementary form will be filed containing, for each year, an allocation of the revenue gains and losses reported in columns (3) and (8) to general and administrative, generation, transmission and distribution.

Franchise Fee

Home Rule Authority Granted by Article VIII, Section 2(b), Florida Constitution, and Section 166.021, Florida Statutes

Article VIII, Section 2(b), Florida Constitution, provides:

> (b) POWERS. Municipalities shall have governmental, corporate and proprietary powers to enable them to conduct municipal government, perform municipal functions and render municipal services, and may exercise any power for municipal purposes except as otherwise provided by law. Each municipal legislative body shall be elective.

Section 166.021, Florida Statutes, grants extensive home rule power to municipalities. A municipality has the complete power to legislate by ordinance for any municipal purpose, except in those situations that a general or special law is inconsistent with the subject matter of the proposed ordinance.

Not all local government revenue sources are taxes requiring general law authorization under Article VII, Section 1(a), Florida Constitution. When a county or municipal revenue source is imposed by ordinance, the judicial test is whether the charge meets the legal sufficiency test, pursuant to Florida case law, for a valid fee or assessment. If not a valid fee or assessment, the charge is a tax and requires general law authorization. If not a tax, the fee or assessment's imposition is within the constitutional and statutory home rule power of municipalities and counties.

When analyzing the validity of a home rule fee, judicial reliance is often placed on the type of governmental power being exercised. Generally, fees fall into two categories. Regulatory fees, such as building permit fees, inspection fees, impact fees, and stormwater fees, are imposed pursuant to the exercise of police powers as regulation of an activity or property. Such regulatory fees cannot exceed the cost of the regulated activity and are generally applied solely to pay the cost of the regulated activity.

In contrast, proprietary fees, such as user fees, rental fees, and franchise fees, are imposed pursuant to the exercise of the proprietary right of government. Such proprietary fees are governed by the principle that the feepayer receives a special benefit or the imposed fee is reasonable in relation to the privilege or service provided. For each fee category, rules have been developed by Florida case law to distinguish a valid fee from a tax.

Local governments may exercise their home rule authority to impose a franchise fee upon a utility for the grant of a franchise and the privilege of using a local government's rights-of-way to conduct the utility business. The franchise fee is considered fair rent for the use of such rights-of-way and consideration for the local government's agreement not to provide competing utility services during the term of the franchise agreement. The imposition of the fee requires the adoption of a franchise agreement, which grants a special privilege that is not available to the general public. Typically, the franchise fee is calculated as a percentage of the utility's gross revenues within a defined geographic area. A fee imposed by a municipality is based upon the gross revenues received from the incorporated area while a fee imposed by a county is generally based upon the gross revenues received from the unincorporated area.

Summaries of prior years' franchise fee revenues as reported by local governments are available.[1]

1. http://edr.state.fl.us/Content/local-government/data/data-a-to-z/index.cfm

Reported County and Municipal Government Franchise Fee-Electricity Revenues

Local Fiscal Years 2004-05 to 2012-13

County Governments

Local Fiscal Year	# Reporting Franchise Fees-Electricity Revenue	Franchise Fees-Electricity Revenue	Total Franchise Fee Revenue	Franchise Fees-Electricity as % of Total Franchise Fees	Total Revenue from All Accounts	Franchise Fees-Electricity as % of Total Revenue
2012-13	13	$ 138,982,436	$ 160,292,116	86.7%	$ 35,293,287,441	0.4%
2011-12	12	$ 142,141,297	$ 163,361,458	87.0%	$ 34,425,008,290	0.4%
2010-11	13	$ 141,763,538	$ 165,239,360	85.8%	$ 35,205,022,317	0.4%
2009-10	12	$ 157,531,114	$ 178,424,425	88.3%	$ 36,374,756,173	0.4%
2008-09	13	$ 157,892,282	$ 178,925,729	88.2%	$ 39,132,778,914	0.4%
2007-08	13	$ 154,336,228	$ 177,647,312	86.9%	$ 41,166,433,921	0.4%
2006-07	13	$ 140,330,361	$ 170,428,497	82.3%	-	-
2005-06	13	$ 142,123,668	$ 171,207,441	83.0%	-	-
2004-05	14	$ 123,553,216	$ 145,991,416	84.6%	-	-

Municipal Governments

Local Fiscal Year	# Reporting Franchise Fees-Electricity Revenue	Franchise Fees-Electricity Revenue	Total Franchise Fee Revenue	Franchise Fees-Electricity as % of Total Franchise Fees	Total Revenue from All Accounts	Franchise Fees-Electricity as % of Total Revenue
2012-13 **	343	$ 546,561,653	$ 656,455,841	83.3%	$ 31,927,999,565	1.7%
2011-12	349	$ 563,206,940	$ 691,485,849	81.4%	$ 32,060,876,417	1.8%
2010-11	345	$ 571,030,032	$ 713,743,133	80.0%	$ 28,173,312,741	2.0%
2009-10	344	$ 565,453,359	$ 705,492,123	80.2%	$ 30,459,315,301	1.9%
2008-09	339	$ 600,243,133	$ 717,295,819	83.7%	$ 28,291,875,774	2.1%
2007-08	331	$ 546,658,421	$ 673,918,453	81.1%	-	-
2006-07	344	$ 546,883,232	$ 669,073,212	81.7%	-	-
2005-06	335	$ 514,540,702	$ 633,075,955	81.3%	-	-
2004-05	340	$ 434,429,008	$ 541,407,060	80.2%	-	-

Combined Total: County and Municipal Governments

Local Fiscal Year	# Reporting Franchise Fees-Electricity Revenue	Franchise Fees-Electricity Revenue				
2012-13 **	356	$ 685,544,089				
2011-12	361	$ 705,348,237				
2010-11	358	$ 712,793,570				
2009-10	356	$ 722,984,473				
2008-09	352	$ 758,135,415				
2007-08	344	$ 700,994,649				
2006-07	357	$ 687,213,593				
2005-06	348	$ 656,664,370				
2004-05	354	$ 557,982,224				

Notes:
1) This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 323.100 - Franchise Fee-Electricity.
2) FY 2012-13 Annual Financial Reports for nine municipalities have not yet been submitted to or certified by the Department of Financial Services. Consequently, the 2012-13 revenue figures are not yet final, and the municipal and combined totals are subject to future revision.

Source: EDR staff compilation of Annual Financial Report (AFR) data obtained from the Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Government.

Summary of Reported County Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Alachua	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Baker	$ 471,629	$ 575,612	$ 646,286	$ 666,262	$ 639,137	$ 612,403	$ 600,133	$ 546,738	$ 513,318
Bay	$ -	$ -	$ -	$ -	$ 72,693	$ -	$ -	$ -	$ -
Bradford	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Brevard	$ 12,532,188	$ 15,737,576	$ 15,487,500	$ 15,547,727	$ 15,863,455	$ 14,172,835	$ 13,812,429	$ 12,713,490	$ 12,601,382
Broward	$ 2,936,000	$ 2,418,000	$ 1,586,000	$ 1,248,000	$ 1,317,000	$ 1,128,000	$ 1,073,000	$ 1,051,000	$ 1,017,000
Calhoun	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Charlotte	$ 7,180,113	$ 8,255,981	$ 8,701,628	$ 8,456,735	$ 9,483,004	$ 8,750,773	$ 8,670,905	$ 8,098,035	$ 8,075,400
Citrus	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Clay	$ 5,799	$ 6,247	$ 7,876	$ -	$ -	$ -	$ -	$ -	$ 6,889
Collier	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,867	$ -	$ -
Columbia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DeSoto	$ -	$ -	$ -	$ 1,268,980	$ -	$ -	$ -	$ -	$ -
Dixie	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Duval	Refer to the separate municipal table for the consolidated City of Jacksonville/Duval County totals.								
Escambia	$ 8,340,603	$ 9,159,224	$ 9,813,723	$ 9,960,518	$ 10,755,776	$ 11,211,278	$ 11,157,471	$ 10,625,833	$ 10,341,711
Flagler	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Franklin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gilchrist	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Glades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gulf	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hamilton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hardee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hendry	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hernando	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Highlands	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hillsborough	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Indian River	$ 6,106,585	$ 7,343,260	$ 7,734,618	$ 7,193,822	$ 7,485,240	$ 7,088,093	$ 6,516,576	$ 6,421,975	$ 6,552,104
Jackson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jefferson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lafayette	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lee	$ 6,911,941	$ 8,835,607	$ 9,352,357	$ 9,161,456	$ 9,293,256	$ 8,406,940	$ 8,398,013	$ 8,012,996	$ 8,354,637
Leon	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Levy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Liberty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Madison	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Manatee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marion	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Miami-Dade	$ 36,616,071	$ 38,723,997	$ 51,813,365	$ 48,668,038	$ 44,241,336	$ 45,059,265	$ 31,608,060	$ 37,925,148	$ 35,535,854
Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nassau	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Okaloosa	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Okeechobee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Osceola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palm Beach	$ 20,836,584	$ 25,022,599	$ 25,495,545	$ 25,042,044	$ 29,913,714	$ 34,017,118	$ 33,262,458	$ 31,407,084	$ 31,120,934
Pasco	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Summary of Reported County Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Polk	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Putnam	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Johns	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Lucie	$ 3,619,311	$ 4,658,497	$ 4,564,374	$ 3,624,277	$ 4,390,381	$ 4,068,691	$ 4,018,521	$ 3,923,615	$ 3,845,968
Santa Rosa	$ 4,247,337	$ 4,643,093	$ 5,110,630	$ 5,224,408	$ 5,807,671	$ 6,074,075	$ 5,976,614	$ 5,749,499	$ 5,670,573
Sarasota	$ 13,749,054	$ 16,743,975	$ -	$ 18,273,961	$ 18,629,619	$ 16,941,643	$ 16,576,491	$ 15,665,884	$ 15,346,666
Seminole	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sumter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Suwannee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taylor	$ -	$ -	$ 16,459	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Volusia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wakulla	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Walton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
County Franchise Fees-Electricity Totals	**$ 123,553,216**	**$ 142,123,668**	**$ 140,330,361**	**$ 154,336,228**	**$ 157,892,282**	**$ 157,531,114**	**$ 141,763,538**	**$ 142,141,297**	**$ 138,982,436**
% Change	**-**	**15.0%**	**-1.3%**	**10.0%**	**2.3%**	**-0.2%**	**-10.0%**	**0.3%**	**-2.2%**
# Reporting	**14**	**13**	**13**	**13**	**13**	**12**	**13**	**12**	**13**
Total County Franchise Fees	**$ 145,991,416**	**$ 171,207,441**	**$ 170,428,497**	**$ 177,647,312**	**$ 178,925,729**	**$ 178,424,425**	**$ 165,239,360**	**$ 163,361,458**	**$ 160,292,116**
% Change	**-**	**17.3%**	**-0.5%**	**4.2%**	**0.7%**	**-0.3%**	**-7.4%**	**-1.1%**	**-1.9%**
Electricity Fees as % of All Fees	**84.6%**	**83.0%**	**82.3%**	**86.9%**	**88.2%**	**88.3%**	**85.8%**	**87.0%**	**86.7%**

Note: This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 323.100 - Franchise Fee - Electricity and 323.XXX - Franchise Fees.

Data Source: Florida Department of Financial Services.

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Alachua	Alachua	$ -	$ -	$ -	$ 221,470	$ 236,906	$ 250,833	$ 253,450	$ 236,672	$ 230,053
Archer	Alachua	$ 42,584	$ 46,929	$ 43,557	$ 102,729	$ 114,766	$ 51,174	$ 46,598	$ 43,991	$ 40,481
Gainesville	Alachua	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hawthorne	Alachua	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
High Springs	Alachua	$ 421,902	$ 249,601	$ 275,776	$ 279,757	$ 344,761	$ 338,324	$ 318,119	$ 310,876	$ 617,836
La Crosse	Alachua	$ 6,890	$ 8,011	$ 7,500	$ -	$ -	$ 11,489	$ 9,334	$ 10,702	$ 9,730
Micanopy	Alachua	$ 26,727	$ 28,768	$ 28,868	$ 27,736	$ 32,724	$ 36,127	$ 30,964	$ 29,201	$ 31,741
Newberry	Alachua	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Waldo	Alachua	$ 45,777	$ 55,606	$ 96,436	$ -	$ 63,365	$ 65,362	$ 58,640	$ 49,665	$ -
Glen St. Mary	Baker	$ 24,884	$ 29,568	$ 30,396	$ 29,949	$ 33,075	$ 32,954	$ 31,653	$ 26,712	$ 26,551
Macclenny	Baker	$ 320,576	$ 337,273	$ 345,846	$ 423,879	$ 534,578	$ 429,475	$ 433,130	$ 399,492	$ 379,615
Callaway	Bay	$ 566,622	$ 596,817	$ 645,870	$ 665,055	$ 747,509	$ 800,500	$ 771,923	$ 684,718	$ 660,398
Lynn Haven	Bay	$ 412,626	$ 452,796	$ 475,731	$ 938,208	$ 1,161,472	$ 1,277,240	$ 1,278,586	$ 1,147,966	$ 1,075,624
Mexico Beach	Bay	$ 112,246	$ 143,360	$ 143,833	$ 145,426	$ 165,277	$ 178,824	$ 188,487	$ 153,842	$ 165,432
Panama City	Bay	$ 1,328,777	$ 1,498,664	$ 1,610,843	$ 1,656,128	$ 1,933,048	$ 2,024,977	$ 3,616,998	$ 3,798,295	$ 4,066,491
Panama City Beach	Bay	$ -	$ 1,289,416	$ 1,595,319	$ 1,821,868	$ 2,194,752	$ 2,372,629	$ 2,346,487	$ 2,223,139	$ 2,151,668
Parker	Bay	$ 242,379	$ 271,618	$ 275,471	$ 296,601	$ 324,508	$ 341,383	$ 323,766	$ 287,959	$ 277,080
Springfield	Bay	$ 377,895	$ 416,517	$ 474,741	$ 438,737	$ 450,865	$ 492,224	$ 476,818	$ 423,864	NR
Brooker	Bradford	$ -	$ -	$ -	$ -	$ -	$ 903	$ -	$ -	$ -
Hampton	Bradford	$ 14,013	$ 10,197	$ 15,712	$ 12,253	$ -	$ 32,326	$ 22,547	$ 15,061	NR
Lawtey	Bradford	$ -	$ -	$ -	$ 39,339	$ -	$ 38,543	$ 38,856	$ -	$ 33,675
Starke	Bradford	$ -	$ -	$ -	$ -	$ 8,345	$ 4,084	$ 3,828	$ 19,350	$ 34,733
Cape Canaveral	Brevard	$ 557,666	$ 667,698	$ 683,177	$ 692,501	$ 683,523	$ 647,499	$ 649,510	$ 600,068	$ 587,974
Cocoa	Brevard	$ 1,046,610	$ 1,297,020	$ 1,297,886	$ 1,270,693	$ 1,300,709	$ 1,180,209	$ 1,191,963	$ 1,133,030	$ 1,129,476
Cocoa Beach	Brevard	$ 986,298	$ 1,190,868	$ 1,224,051	$ 1,156,673	$ 1,190,232	$ 1,091,702	$ 1,034,146	$ 1,116,122	$ 987,689
Grant-Valkaria	Brevard	$ -	$ -	$ 212,980	$ 230,885	$ 241,875	$ 228,574	$ 225,216	$ 207,602	$ 213,748
Indialantic	Brevard	$ 183,047	$ 217,583	$ 239,690	$ 226,691	$ 227,668	$ 213,818	$ 206,211	$ 189,684	$ 188,779
Indian Harbour Beach	Brevard	$ 413,390	$ 492,869	$ 538,792	$ 529,359	$ 539,290	$ 500,037	$ 475,557	$ 454,455	$ 442,029
Malabar	Brevard	$ 181,805	$ 213,100	$ 215,623	$ 213,516	$ 228,984	$ 198,329	$ 195,544	$ 186,807	$ 190,111
Melbourne	Brevard	$ 4,974,195	$ 6,173,236	$ 6,276,793	$ 6,293,070	$ 6,431,843	$ 5,778,051	$ 5,752,188	$ 5,467,971	$ 5,377,774
Melbourne Beach	Brevard	$ 176,876	$ 208,843	$ 216,154	$ 181,843	$ 205,226	$ 195,244	$ 189,737	$ 174,417	$ 171,134
Melbourne Village	Brevard	$ 61,907	$ 74,340	$ 75,082	$ 69,725	$ 53,202	$ 45,872	$ 44,471	$ 39,912	$ 39,718
Palm Bay	Brevard	$ 4,441,916	$ 5,562,896	$ 5,637,594	$ 5,573,179	$ 5,741,378	$ 5,163,119	$ 5,011,689	$ 4,697,001	$ 4,675,829
Palm Shores	Brevard	$ 34,364	$ 36,919	$ 37,230	$ 42,587	$ 49,075	$ 50,319	$ 50,065	$ 49,311	$ 48,827
Rockledge	Brevard	$ 1,377,667	$ 1,662,341	$ 1,700,134	$ 1,682,008	$ 1,716,625	$ 1,590,914	$ 1,531,273	$ 1,478,627	$ 1,429,138
Satellite Beach	Brevard	$ 547,440	$ 653,305	$ 643,476	$ 637,067	$ 644,669	$ 603,371	$ 590,433	$ 558,333	$ 536,203
Titusville	Brevard	$ 2,092,020	$ 2,291,105	$ 2,762,179	$ 2,918,736	$ 2,925,336	$ 2,703,754	$ 2,599,200	$ 2,691,962	$ 2,607,744
West Melbourne	Brevard	$ 910,862	$ 1,107,317	$ 1,284,738	$ 1,197,833	$ 1,292,131	$ 1,246,858	$ 1,239,494	$ 1,230,101	$ 1,230,206
Coconut Creek	Broward	$ 2,383,188	$ 2,833,018	$ 3,045,084	$ 3,063,821	$ 3,054,942	$ 2,800,613	$ 2,773,296	$ 2,707,920	$ 2,656,729
Cooper City	Broward	$ 1,587,067	$ 1,840,050	$ 1,908,140	$ 1,896,251	$ 1,846,252	$ 1,711,493	$ 1,720,391	$ 1,695,675	$ 1,695,029
Coral Springs	Broward	$ 6,507,760	$ 7,931,211	$ 8,095,887	$ 8,282,502	$ 8,039,262	$ 7,165,628	$ 7,050,212	$ 6,738,442	$ 6,609,005
Dania Beach	Broward	$ 1,872,196	$ 2,197,867	$ 2,268,676	$ 2,270,251	$ 2,246,823	$ 2,041,381	$ 2,022,391	$ 1,950,481	$ 1,949,911
Davie	Broward	$ 5,355,336	$ -	$ 7,017,500	$ 6,966,990	$ 6,860,451	$ 6,194,801	$ 6,124,735	$ 5,889,619	$ 5,841,186
Deerfield Beach	Broward	$ 4,263,366	$ 5,492,939	$ 6,983,852	$ 5,877,311	$ 5,686,502	$ 5,100,276	$ 5,049,066	$ 4,865,482	$ 4,717,719
Fort Lauderdale	Broward	$ 13,909,709	$ 16,761,929	$ 17,819,523	$ 17,797,219	$ 17,633,250	$ 17,872,611	$ 16,141,012	$ 15,561,277	$ 15,140,240
Hallandale Beach	Broward	$ 2,278,360	$ 2,577,780	$ 2,724,983	$ 2,786,854	$ 2,732,867	$ 2,481,413	$ 2,519,550	$ 2,456,175	$ 2,402,527
Hillsboro Beach	Broward	$ 188,267	$ 219,054	$ 257,900	$ 245,136	$ 246,339	$ 246,086	$ 237,383	$ 216,343	$ 206,694
Hollywood	Broward	$ 8,811,193	$ 10,434,800	$ 10,736,830	$ 10,594,802	$ 10,485,470	$ 9,392,210	$ 9,431,746	$ 9,035,845	$ 8,761,378
Lauderdale Lakes	Broward	$ 1,286,543	$ 1,539,269	$ 1,612,148	$ 1,565,488	$ 1,527,934	$ 1,406,787	$ 1,407,536	$ 1,356,543	$ 1,332,302
Lauderdale-By-The-Sea	Broward	$ 451,492	$ 622,572	$ 637,905	$ 673,126	$ 685,129	$ 633,159	$ 602,298	$ 589,980	$ 573,324
Lauderhill	Broward	$ 2,282,241	$ 2,922,651	$ 3,281,621	$ 3,034,828	$ 3,190,431	$ 2,969,527	$ 2,871,472	$ 2,753,763	$ 2,683,378

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Lazy Lake	Broward	$ 1,000	$ -	$ -	$ -	$ 2,573	$ 2,224	$ 2,396	$ 2,488	$ 2,256
Lighthouse Point	Broward	$ 713,584	$ 831,451	$ 918,936	$ 895,238	$ 900,765	$ 849,827	$ 812,192	$ 865,227	$ 767,419
Margate	Broward	$ 2,586,517	$ 3,045,228	$ 3,070,973	$ 2,971,816	$ 2,927,185	$ 2,684,419	$ 2,614,197	$ 2,553,154	$ 2,482,056
Miramar	Broward	$ 4,708,895	$ 5,839,055	$ 6,148,674	$ 6,318,987	$ 6,353,815	$ 6,044,951	$ 6,094,669	$ 5,886,026	$ 5,829,325
North Lauderdale	Broward	$ 1,372,313	$ 1,612,881	$ 1,642,869	$ 1,705,840	$ 1,624,932	$ 1,489,369	$ 1,490,409	$ 1,461,469	$ 1,440,963
Oakland Park	Broward	$ 2,012,204	$ 2,569,096	$ 2,856,998	$ 2,841,921	$ 2,768,332	$ 2,490,621	$ 2,455,175	$ 2,360,322	$ 2,318,315
Parkland	Broward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pembroke Park	Broward	$ 390,415	$ 474,491	$ 578,462	$ 700,037	$ 650,134	$ 565,375	$ 578,242	$ 557,612	$ 549,335
Pembroke Pines	Broward	$ 7,448,243	$ 8,958,121	$ 9,184,098	$ 9,176,429	$ 9,208,117	$ 8,401,468	$ 8,339,056	$ 8,059,519	$ 7,852,194
Plantation	Broward	$ 5,579,266	$ 6,633,619	$ 7,566,031	$ 6,896,141	$ 6,751,937	$ 6,202,063	$ 6,028,547	$ 5,774,563	$ 5,006,920
Pompano Beach	Broward	$ 7,359,789	$ 8,670,163	$ 8,984,290	$ 8,995,884	$ 8,861,010	$ 7,817,129	$ 7,734,548	$ 7,474,946	$ 7,291,113
Sea Ranch Lakes	Broward	$ 55,812	$ 65,289	$ 69,858	$ 77,753	$ 80,030	$ 64,440	$ 63,791	$ 60,746	$ 59,356
Southwest Ranches	Broward	$ 412,328	$ 518,384	$ 577,507	$ 578,628	$ 585,780	$ 571,442	$ 573,740	$ 555,873	$ 544,508
Sunrise	Broward	$ 5,292,515	$ 5,928,168	$ 6,131,307	$ 6,139,228	$ 6,234,903	$ 6,165,104	$ 5,495,708	$ 5,322,020	$ 5,282,356
Tamarac	Broward	$ 3,060,737	$ 3,603,109	$ 3,652,848	$ 3,590,765	$ 3,525,046	$ 3,247,694	$ 3,126,258	$ 3,058,986	$ 4,714,972
West Park	Broward	$ 150,645	$ 542,031	$ 581,035	$ 559,939	$ 550,073	$ 512,727	$ 505,968	$ 495,192	$ 484,197
Weston	Broward	$ 3,519,731	$ 4,263,679	$ 4,347,976	$ 4,326,474	$ 4,305,680	$ 4,129,670	$ 4,101,096	$ 3,902,012	$ 3,741,992
Wilton Manors	Broward	$ 628,226	$ 747,103	$ 719,424	$ 1,009,522	$ 811,339	$ 757,399	$ 750,266	$ 726,228	$ 717,779
Altha	Calhoun	$ 20,600	$ 19,773	$ 20,657	$ 36,526	$ 41,326	$ 51,746	$ 31,712	$ 31,921	$ 38,897
Blountstown	Calhoun	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Punta Gorda	Charlotte	$ 1,097,441	$ 1,304,970	$ 1,316,010	$ 1,350,700	$ 1,435,888	$ 1,340,371	$ 1,311,751	$ 1,217,206	$ 1,198,571
Crystal River	Citrus	$ 366,429	$ 428,137	$ 432,817	$ 421,803	$ 457,393	$ 495,655	$ 465,007	$ 423,928	$ 432,058
Inverness	Citrus	$ 509,407	$ 604,374	$ 608,068	$ 592,095	$ 658,800	$ 691,761	$ 637,754	$ 604,242	$ 635,238
Green Cove Springs	Clay	$ -	$ -	$ -	$ -	$ -	$ 63,280	$ 33,840	$ 33,615	$ -
Keystone Heights	Clay	$ 55,432	$ 53,113	$ 60,811	$ -	$ -	$ -	$ -	$ -	$ -
Orange Park	Clay	$ 545,738	$ 671,564	$ 670,748	$ 735,938	$ -	$ 858,724	$ 914,739	$ 819,554	$ 782,043
Penney Farms	Clay	$ 30,469	$ 36,650	$ 38,680	$ 37,030	$ 39,065	$ 36,882	$ 37,289	$ 34,270	$ 32,749
Everglades	Collier	$ 23,433	$ -	$ -	$ -	$ 31,605	$ 92,363	$ 2,932	$ 2,079	$ -
Marco Island	Collier	$ 1,531,856	$ 1,882,013	$ 1,913,134	$ 1,920,620	$ 1,610,117	$ -	$ -	$ -	$ -
Naples	Collier	$ 3,141,221	$ 3,791,989	$ 3,832,371	$ 3,703,141	$ 3,903,008	$ 3,420,527	$ 3,394,918	$ 3,286,415	$ 3,215,470
Fort White	Columbia	$ 22,542	$ 31,925	$ 39,676	$ 38,206	$ 45,927	$ 42,971	$ 43,344	$ 38,125	$ 38,304
Lake City	Columbia	$ 944,156	$ 1,133,685	$ 1,242,297	$ 1,248,149	$ 1,339,765	$ 1,210,237	$ 1,170,416	$ 1,096,609	$ 1,051,855
Arcadia	De Soto	$ 458,043	$ 624,740	$ 647,771	$ 494,464	$ 475,917	$ 428,920	$ 418,752	$ 389,506	NR
Cross City	Dixie	$ 102,805	$ 111,821	$ 110,328	$ 106,056	$ 109,016	$ 131,586	$ 124,547	$ 113,188	$ 108,049
Horseshoe Beach	Dixie	$ 15,101	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Atlantic Beach	Duval	$ 613,049	$ 717,986	$ 696,477	$ 769,237	$ 893,612	$ 901,589	$ 930,890	$ 832,138	$ 799,803
Baldwin	Duval	$ 89,735	$ 98,992	$ 94,774	$ 115,957	$ 126,766	$ 131,332	$ 124,174	$ 140,715	$ 112,040
Jacksonville	Duval	$ -	$ -	$ -	$ -	$ 31,000,365	$ 30,706,114	$ 32,591,566	$ 29,461,951	$ 27,888,771
Jacksonville Beach	Duval	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Neptune Beach	Duval	$ 283,515	$ 256,220	$ 211,846	$ 233,985	$ 227,387	$ 239,409	$ 241,795	$ 224,175	$ 218,353
Century	Escambia	$ 53,258	$ 103,990	$ 86,617	$ -	$ 104,633	$ 80,823	$ 133,653	$ 103,019	$ 91,366
Pensacola	Escambia	$ 4,062,816	$ 4,623,060	$ 4,972,086	$ 5,049,347	$ 5,802,384	$ 6,240,353	$ 6,158,610	$ 5,504,301	$ 5,152,478
Beverly Beach	Flagler	$ 19,804	$ 21,689	$ 21,641	$ 20,864	$ -	$ -	$ -	$ -	$ 28,338
Bunnell	Flagler	$ 135,832	$ 181,023	$ 205,104	$ 260,068	$ 243,315	$ 213,722	$ 239,362	$ 219,767	$ 221,422
Palm Coast	Flagler	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marineland	Flagler/St. Johns	$ 9,670	$ 12,934	$ 11,017	$ 9,323	$ 30,666	$ 16,345	$ 15,837	$ 14,008	$ 13,690
Flagler Beach	Flagler/Volusia	$ 262,263	$ 314,509	$ 288,629	$ 283,642	$ 304,667	$ 302,196	$ 296,516	$ 271,454	$ 277,502
Apalachicola	Franklin	$ 130,216	$ 156,752	$ 165,060	$ 163,278	$ 173,127	$ 185,173	$ 182,341	$ 147,570	$ 144,720
Carrabelle	Franklin	$ 115,433	$ 138,501	$ 107,993	$ 90,401	$ 106,105	$ 101,375	$ 107,971	$ 96,004	$ 91,476
Chattahoochee	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Greensboro	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Gretna	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	NR
Havana	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Midway	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Quincy	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	NR
Bell	Gilchrist	$ 31,453	$ 40,552	$ 40,595	$ 64,873	$ 63,304	$ 67,432	$ 67,028	$ 61,275	$ 58,621
Trenton	Gilchrist	$ 85,008	$ 94,309	$ 99,592	$ 94,389	$ 100,020	$ 121,120	$ 107,697	$ 97,223	$ 89,719
Fanning Springs	Gilchrist/Levy	$ 42,345	$ 51,352	$ 51,343	$ 51,126	$ 54,446	$ 58,636	$ 55,347	$ 51,665	$ 48,687
Moore Haven	Glades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Port St. Joe	Gulf	$ 141,148	$ 180,497	$ 186,951	$ 184,489	$ 203,889	$ 199,083	$ 204,749	$ 186,408	$ -
Wewahitchka	Gulf	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jasper	Hamilton	$ 82,364	$ 102,084	$ 104,064	$ 71,153	$ 101,208	$ 108,640	$ 72,674	$ 69,071	$ 104,919
Jennings	Hamilton	$ 36,124	$ 47,405	$ 39,224	$ 41,097	$ 45,734	$ 48,438	$ 44,136	$ 41,082	$ 38,537
White Springs	Hamilton	$ 34,648	$ 36,863	$ 34,106	$ 33,897	$ 37,933	$ 41,096	$ 37,318	$ 31,209	$ 28,966
Bowling Green	Hardee	$ 74,524	$ 85,606	$ 81,610	$ 93,521	$ 91,212	$ 101,561	$ 102,384	$ 82,509	$ 85,771
Wauchula	Hardee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Zolfo Springs	Hardee	$ 56,298	$ 72,527	$ 65,990	$ 76,289	$ 71,678	$ 83,296	$ 78,086	$ 65,278	$ 64,829
Clewiston	Hendry	$ 5,091	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LaBelle	Hendry	$ 272,485	$ 291,926	$ 337,799	$ 332,997	$ 343,360	$ 326,532	$ 312,146	$ 292,228	$ 276,535
Brooksville	Hernando	$ 501,562	$ 580,514	$ 574,367	$ 594,958	$ 706,233	$ 739,233	$ 672,875	$ 726,801	$ 603,249
Weeki Wachee	Hernando	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avon Park	Highlands	$ 429,904	$ 501,246	$ 525,566	$ 506,834	$ 573,547	$ 588,423	$ 532,794	$ 523,526	$ 497,712
Lake Placid	Highlands	$ 155,241	$ 184,963	$ 189,504	$ 188,267	$ 202,111	$ 211,300	$ 195,032	$ 191,865	$ 183,986
Sebring	Highlands	$ 715,861	$ 879,373	$ 956,317	$ 845,665	$ 996,516	$ 1,052,651	$ 979,805	$ 944,095	$ 874,166
Plant City	Hillsborough	$ 2,081,123	$ 2,297,086	$ 2,477,595	$ 2,450,539	$ 2,474,062	$ 2,432,326	$ 3,506,028	$ 3,491,415	$ 3,415,770
Tampa	Hillsborough	$ 21,686,857	$ 24,214,731	$ 25,926,448	$ 25,702,784	$ 27,122,835	$ 27,209,322	$ 25,246,733	$ 31,646,686	$ 30,893,083
Temple Terrace	Hillsborough	$ 1,423,006	$ 1,602,668	$ 1,919,658	$ 1,776,564	$ 1,958,555	$ 1,971,044	$ 1,840,769	$ 1,764,912	$ 1,683,010
Bonifay	Holmes	$ 93,394	$ 100,198	$ 108,955	$ 110,444	$ 124,905	$ 135,269	$ 134,433	$ 120,152	$ 112,491
Esto	Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Noma	Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ponce de Leon	Holmes	$ 23,129	$ 27,623	$ 31,453	$ -	$ -	$ -	$ -	$ -	$ -
Westville	Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fellsmere	Indian River	$ 83,687	$ 108,161	$ 106,683	$ 131,557	$ 178,358	$ 169,327	$ 170,944	$ 168,876	$ 176,807
Indian River Shores	Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orchid	Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sebastian	Indian River	$ 836,694	$ 1,203,191	$ 1,055,082	$ 1,140,994	$ 1,260,484	$ 1,159,433	$ 1,117,525	$ 1,052,299	$ 1,040,067
Vero Beach	Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Alford	Jackson	$ 15,000	$ -	$ 21,267	$ 26,115	$ 32,898	$ 40,856	$ 33,918	$ 35,174	$ 31,015
Bascom	Jackson	$ 2,337	$ 2,609	$ 2,626	$ 3,685	$ 4,078	$ 4,626	$ 4,626	$ 3,827	$ 4,152
Campbellton	Jackson	$ 6,071	$ 6,460	$ 6,630	$ 6,506	$ 9,052	$ 9,411	$ 8,965	$ 7,932	$ 7,727
Cottondale	Jackson	$ 46,966	$ 48,895	$ -	$ 60,446	$ 82,853	$ 102,409	$ 84,788	$ 73,002	$ 71,522
Graceville	Jackson	$ 61,000	$ 69,367	$ 80,094	$ 77,302	$ 98,497	$ 102,036	$ 100,544	$ 91,883	$ 86,886
Grand Ridge	Jackson	$ 25,676	$ -	$ 30,273	$ 31,947	$ 36,707	$ 35,780	$ 36,427	$ 33,977	$ 33,801
Greenwood	Jackson	$ 11,690	$ 16,862	$ 26,861	$ 33,203	$ -	$ -	$ -	$ -	$ -
Jacob City	Jackson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Malone	Jackson	$ 32,491	$ 45,623	$ 52,088	$ 67,090	$ 76,598	$ 92,546	$ 79,672	$ 82,734	$ 75,304
Marianna	Jackson	$ 353,100	$ 369,000	$ 379,800	$ 552,285	$ 913,484	$ 916,846	$ 870,207	$ 806,691	$ 864,387
Sneads	Jackson	$ 75,615	$ 87,875	$ 88,827	$ 93,408	$ 98,118	$ 102,155	$ 97,326	$ 93,438	$ 93,395
Monticello	Jefferson	$ 127,809	$ 154,488	$ 139,631	$ 148,340	$ 166,959	$ 185,515	$ 177,768	$ 172,509	$ 201,362
Mayo	Lafayette	$ 41,575	$ 50,101	$ 58,137	$ 51,346	$ 56,306	$ 58,752	$ 50,198	$ 49,889	$ 45,411
Astatula	Lake	$ 69,523	$ 80,935	$ 76,071	$ 86,312	$ 68,349	$ 74,042	$ 71,216	$ 61,173	NR
Clermont	Lake	$ 1,169,638	$ 1,494,872	$ 1,599,583	$ 1,678,227	$ 1,933,677	$ 2,154,843	$ 2,068,814	$ 1,995,234	$ 1,899,998

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Eustis	Lake	$ 932,538	$ 1,107,760	$ 1,166,947	$ 1,146,237	$ 1,249,754	$ 1,336,960	$ 1,219,537	$ 1,177,526	$ 1,092,308
Fruitland Park	Lake	$ 211,320	$ 257,771	$ 278,894	$ 318,612	$ 348,609	$ 342,910	$ 320,396	$ 284,303	$ 301,254
Groveland	Lake	$ 228,587	$ 318,178	$ 355,694	$ 379,150	$ 421,006	$ 474,517	$ 455,872	$ 459,279	NR
Howey-in-the-Hills	Lake	$ 55,793	$ 75,980	$ 63,240	$ -	$ 67,980	$ 74,741	$ 67,024	$ 63,960	$ 58,440
Lady Lake	Lake	$ 772,785	$ 946,571	$ 938,773	$ 958,601	$ 1,117,179	$ 1,264,885	$ 1,177,072	$ 1,111,871	$ 1,091,998
Leesburg	Lake	$ 12,770	$ 15,714	$ 25,498	$ 37,835	$ 42,496	$ 48,296	$ 48,180	$ 54,384	$ 54,995
Mascotte	Lake	$ 117,995	$ 157,286	$ 162,663	$ 171,220	$ 189,378	$ 203,607	$ 195,880	$ 180,958	$ 178,907
Minneola	Lake	$ -	$ 377,611	$ 387,161	$ 394,580	$ 442,793	$ 490,096	$ 476,418	$ 448,954	$ 442,249
Montverde	Lake	$ 63,561	$ 82,007	$ 76,205	$ 96,672	$ 88,946	$ 95,431	$ 89,669	$ 86,033	$ 87,477
Mount Dora	Lake	$ 268,101	$ 319,110	$ 340,261	$ 359,160	$ 412,893	$ 447,214	$ 444,303	$ 415,892	$ 398,975
Tavares	Lake	$ 667,328	$ 812,941	$ 840,086	$ 872,361	$ 969,699	$ 1,039,617	$ 1,000,206	$ 945,806	$ 921,014
Umatilla	Lake	$ 149,507	$ 181,141	$ 177,160	$ 173,359	$ 197,579	$ -	$ 216,346	$ 205,115	$ 195,522
Bonita Springs	Lee	$ 1,477,608	$ 1,829,649	$ 1,952,087	$ 1,957,041	$ 1,974,467	$ 1,782,542	$ 2,042,563	$ 1,967,312	$ 1,950,904
Cape Coral	Lee	$ 3,774,618	$ 4,589,753	$ 5,025,118	$ 5,003,339	$ 5,351,886	$ 5,646,428	$ 5,496,923	$ 5,429,804	$ 5,148,353
Fort Myers	Lee	$ 4,032,445	$ 5,082,057	$ 5,579,511	$ 5,788,331	$ 5,893,656	$ 5,161,624	$ 5,197,931	$ 5,016,768	$ 4,948,431
Fort Myers Beach	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sanibel	Lee	$ 389,993	$ 444,188	$ 508,879	$ 510,284	$ 512,625	$ 568,000	$ 583,639	$ 561,067	$ 540,803
Tallahassee	Leon	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bronson	Levy	$ -	$ -	$ 69,979	$ 71,518	$ 80,064	$ 85,580	$ 80,699	$ 75,418	$ 75,598
Cedar Key	Levy	$ 38,709	$ 45,913	$ 44,464	$ 44,262	$ 47,155	$ 51,491	$ 49,661	$ 48,574	$ 47,533
Chiefland	Levy	$ 202,238	$ 235,927	$ 241,669	$ 255,643	$ 272,373	$ 289,815	$ 277,629	$ 269,271	$ 257,118
Inglis	Levy	$ 79,987	$ 94,262	$ 91,067	$ 94,903	$ 105,657	$ 108,871	$ 98,519	$ 89,800	$ 87,571
Otter Creek	Levy	$ 4,983	$ 6,099	$ 5,658	$ 5,542	$ 5,962	$ 6,443	$ 6,491	$ 5,819	$ 5,762
Williston	Levy	$ 31,540	$ 40,195	$ 39,294	$ 40,125	$ 27,008	$ 31,070	$ 36,685	$ 36,484	$ 21,784
Yankeetown	Levy	$ 31,333	$ 41,836	$ 35,627	$ 36,046	$ 38,268	$ 42,912	$ 40,063	$ 36,359	$ 35,278
Bristol	Liberty	$ 29,291	$ 27,202	$ 27,455	$ 42,366	$ 52,464	$ 61,006	$ 59,634	$ 54,854	$ 47,860
Greenville	Madison	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lee	Madison	$ 14,997	$ 17,394	$ 18,300	$ 18,773	$ 19,975	$ 21,441	$ 19,164	$ 16,942	$ 16,207
Madison	Madison	$ 167,162	$ 208,651	$ 212,023	$ 206,579	$ 230,267	$ 246,112	$ 228,525	$ 209,380	$ 200,640
Anna Maria	Manatee	$ 126,755	$ 153,259	$ 154,795	$ 153,423	$ 164,901	$ 160,657	$ 160,652	$ 154,131	$ 160,786
Bradenton	Manatee	$ 2,728,834	$ 3,465,543	$ 3,391,904	$ 3,261,363	$ 3,304,933	$ 2,970,333	$ 2,963,536	$ 2,830,719	$ 2,770,869
Bradenton Beach	Manatee	$ 118,529	$ 160,590	$ 141,116	$ 123,196	$ 166,263	$ 140,735	$ 158,312	$ 107,915	$ 134,681
Holmes Beach	Manatee	$ 333,174	$ 391,610	$ 443,043	$ 405,387	$ 424,017	$ 402,298	$ 407,989	$ 386,992	$ 388,512
Palmetto	Manatee	$ 497,608	$ 656,332	$ 745,697	$ 745,800	$ 775,603	$ 708,104	$ 801,522	$ 824,763	$ 802,827
Longboat Key	Manatee/Sarasota	$ 871,853	$ 1,008,427	$ 1,037,110	$ 1,020,078	$ 1,045,372	$ 957,198	$ 925,048	$ 843,299	$ 752,764
Belleview	Marion	$ 292,307	$ 380,290	$ 354,307	$ 369,038	$ 398,092	$ 427,006	$ 475,789	$ 378,532	$ 367,674
Dunnellon	Marion	$ 167,490	$ 198,972	$ 199,958	$ 192,324	$ 434,495	$ 230,817	$ 209,157	$ 191,867	$ 184,393
McIntosh	Marion	$ 28,420	$ 28,878	$ 27,570	$ 27,117	$ 28,658	$ 28,797	$ 30,122	$ 25,694	$ 25,368
Ocala	Marion	$ 76,165	$ 132,042	$ 179,252	$ 262,381	$ 311,401	$ 369,415	$ 346,496	$ 343,946	$ 340,139
Reddick	Marion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jupiter Island	Martin	$ 120,759	$ 145,953	$ 180,090	$ 177,390	$ 208,723	$ 206,102	$ 220,983	$ 201,155	$ 89,492
Ocean Breeze	Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sewall's Point	Martin	$ 135,362	$ 163,592	$ 167,490	$ 168,628	$ 191,253	$ 182,553	$ 171,957	$ 184,122	$ 148,903
Stuart	Martin	$ 1,322,769	$ 1,751,010	$ 1,744,532	$ 1,748,832	$ 1,873,808	$ 1,596,946	$ 1,625,007	$ 1,564,982	$ 1,519,687
Aventura	Miami-Dade	$ 1,980,272	$ 2,906,200	$ 3,760,394	$ 3,762,159	$ 3,130,232	$ 3,196,576	$ 2,212,081	$ 2,580,362	$ 2,328,313
Bal Harbour	Miami-Dade	$ 511,693	$ 617,026	$ 637,186	$ 657,595	$ 669,745	$ 579,548	$ 637,215	$ 665,588	$ 652,063
Bay Harbor Islands	Miami-Dade	$ 291,150	$ 330,646	$ 357,864	$ 358,628	$ 345,739	$ 318,734	$ 339,235	$ 323,705	$ 326,737
Biscayne Park	Miami-Dade	$ 107,703	$ 122,750	$ 125,523	$ 115,686	$ 112,916	$ 120,595	$ 122,163	$ 111,947	$ 112,685
Coral Gables	Miami-Dade	$ 4,416,461	$ 5,338,021	$ 5,518,767	$ 5,518,706	$ 5,470,371	$ 4,682,462	$ 4,498,854	$ 4,606,645	$ 4,546,595
Cutler Bay	Miami-Dade	$ -	$ 960,000	$ 1,373,216	$ 1,563,517	$ 1,625,066	$ 1,669,404	$ 1,219,797	$ 1,415,237	$ 1,314,553
Doral	Miami-Dade	$ 1,480,502	$ 1,774,080	$ 2,398,014	$ 4,704,277	$ 4,945,893	$ 4,991,887	$ 3,563,838	$ 4,136,741	$ 3,804,585

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
El Portal	Miami-Dade	$ 76,869	$ 108,453	$ 108,819	$ 106,811	$ 93,404	$ 89,342	$ 87,700	$ 83,557	$ 81,770
Florida City	Miami-Dade	$ 403,923	$ 493,908	$ 503,862	$ 579,217	$ 650,397	$ 537,019	$ 501,814	$ 559,738	$ 550,210
Golden Beach	Miami-Dade	$ 94,450	$ 108,905	$ 119,340	$ 121,120	$ 131,809	$ 116,581	$ 112,680	$ 108,876	$ 108,619
Hialeah	Miami-Dade	$ 8,574,100	$ 10,548,228	$ 11,469,814	$ 11,344,580	$ 11,174,635	$ 9,957,417	$ 10,104,878	$ 9,972,894	$ 9,828,418
Hialeah Gardens	Miami-Dade	$ 668,185	$ 820,764	$ 906,639	$ 1,017,141	$ 1,051,650	$ 914,010	$ 909,495	$ 906,820	$ 877,192
Homestead	Miami-Dade	$ 1,682,412	$ 2,548,933	$ 2,548,933	$ 2,095,401	$ 2,065,706	$ 2,056,218	$ 2,083,687	$ 2,176,224	$ 2,261,120
Indian Creek	Miami-Dade	$ 28,442	$ 38,014	$ 47,279	$ 46,440	$ 53,892	$ 52,520	$ 50,127	$ 51,713	$ 49,394
Key Biscayne	Miami-Dade	$ 705,810	$ 1,088,929	$ 1,113,194	$ -	$ 992,997	$ 1,006,415	$ 735,519	$ 846,252	$ 780,245
Medley	Miami-Dade	$ 852,039	$ 1,105,592	$ 1,175,680	$ 1,226,641	$ 1,072,289	$ 883,416	$ 863,375	$ 836,114	$ 840,745
Miami	Miami-Dade	$ 25,463,385	$ 22,676,598	$ 24,606,313	$ 24,797,619	$ 25,131,826	$ 25,119,661	$ 26,500,677	$ 26,257,819	$ 25,754,584
Miami Beach	Miami-Dade	$ 6,384,499	$ 7,448,932	$ 8,169,741	$ 8,218,820	$ 8,651,684	$ 7,928,026	$ 7,505,515	$ 8,795,911	$ 7,323,875
Miami Gardens	Miami-Dade	$ 2,423,973	$ 4,069,708	$ 3,477,481	$ 4,188,860	$ 3,978,584	$ 4,038,941	$ 2,957,525	$ 3,358,782	$ 3,023,802
Miami Lakes	Miami-Dade	$ 1,263,596	$ 1,579,595	$ 2,079,921	$ 2,001,376	$ 1,967,915	$ 2,008,171	$ 1,444,179	$ 1,673,746	$ 1,550,625
Miami Shores	Miami-Dade	$ 550,245	$ 675,768	$ 696,434	$ -	$ 673,853	$ 708,239	$ 652,393	$ 624,427	$ 613,880
Miami Springs	Miami-Dade	$ 797,020	$ 966,572	$ 961,583	$ 889,258	$ 903,118	$ 816,375	$ 798,665	$ 789,584	$ 776,757
North Bay	Miami-Dade	$ 285,868	$ 412,621	$ 349,850	$ 407,627	$ 406,972	$ 366,318	$ 366,318	$ 358,848	$ 363,253
North Miami	Miami-Dade	$ 2,310,141	$ 2,905,463	$ 3,032,246	$ 2,863,689	$ 2,834,321	$ 2,607,189	$ 2,676,516	$ 2,550,538	$ 2,550,826
North Miami Beach	Miami-Dade	$ 1,396,019	$ 1,733,317	$ 1,845,440	$ 1,823,667	$ 2,253,705	$ 2,166,762	$ 1,947,075	$ 1,883,861	$ 1,838,292
Opa-locka	Miami-Dade	$ 655,753	$ 1,210,496	$ 1,121,431	$ 872,976	$ 1,075,527	$ 963,009	$ 1,028,182	$ 986,134	$ 964,279
Palmetto Bay	Miami-Dade	$ 828,052	$ 837,003	$ 1,169,359	$ 1,371,130	$ 1,308,472	$ 1,345,736	$ 960,331	$ 1,101,516	$ 1,016,281
Pinecrest	Miami-Dade	$ 950,314	$ 1,367,111	$ 1,746,727	$ 1,705,563	$ 1,317,317	$ 1,343,813	$ 986,201	$ 1,119,946	$ 1,033,041
South Miami	Miami-Dade	$ 784,923	$ 977,142	$ 1,083,944	$ 1,115,721	$ 1,197,171	$ 1,069,053	$ 1,036,304	$ 1,018,050	$ 981,428
Sunny Isles Beach	Miami-Dade	$ 762,516	$ 1,129,812	$ 1,528,521	$ 1,627,264	$ 1,426,449	$ 1,564,781	$ 1,098,671	$ 1,284,676	$ 1,188,084
Surfside	Miami-Dade	$ 361,722	$ 434,977	$ 442,273	$ 432,283	$ 416,728	$ 385,837	$ 391,566	$ 376,976	$ 368,011
Sweetwater	Miami-Dade	$ 408,908	$ 483,341	$ 502,933	$ 502,566	$ 490,957	$ 447,544	$ 432,233	$ 474,525	$ 446,972
Virginia Gardens	Miami-Dade	$ 146,208	$ 188,657	$ 209,940	$ 209,356	$ 212,043	$ 183,864	$ 177,425	$ 178,588	$ 170,325
West Miami	Miami-Dade	$ 202,746	$ 235,603	$ 284,491	$ 287,745	$ 297,570	$ 278,762	$ 270,730	$ 268,655	$ 257,628
Islamorada	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Key Colony Beach	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Key West	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Layton	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marathon	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Callahan	Nassau	$ 121,497	$ 142,147	$ 152,804	$ 153,303	$ 163,298	$ 145,655	$ 129,464	$ 130,610	$ 128,457
Fernandina Beach	Nassau	$ 822,067	$ 831,604	$ 1,292,915	$ 1,467,039	$ 1,758,124	$ 1,847,508	$ 1,206,131	$ 1,252,097	$ 1,347,538
Hilliard	Nassau	$ 160,670	$ 191,408	$ 201,040	$ 198,340	$ 222,850	$ 212,351	$ 204,627	$ 188,739	$ 183,582
Cinco Bayou	Okaloosa	$ 44,798	$ 50,211	$ 51,767	$ 51,495	$ 57,942	$ 59,420	$ 58,617	$ 53,246	$ 49,799
Crestview	Okaloosa	$ 611,381	$ 784,002	$ 1,346,141	$ 822,091	$ 967,560	$ 1,346,925	$ 1,590,235	$ 1,497,581	$ 1,407,475
Destin	Okaloosa	$ 1,088,202	$ 1,155,561	$ 1,283,015	$ 1,295,396	$ 1,482,122	$ 1,602,758	$ 1,574,434	$ 1,469,746	$ 1,385,058
Fort Walton Beach	Okaloosa	$ 1,324,954	$ 1,491,680	$ 1,607,183	$ 1,649,285	$ 1,845,167	$ 1,900,433	$ 1,903,039	$ 1,710,393	$ 1,583,907
Laurel Hill	Okaloosa	$ 13,421	$ 14,220	$ 17,991	$ 20,359	$ 18,886	$ 23,342	$ -	$ 19,034	$ 18,394
Mary Esther	Okaloosa	$ 160,415	$ 178,681	$ 187,611	$ 173,846	$ 201,440	$ 209,471	$ 201,296	$ 183,037	$ 171,023
Niceville	Okaloosa	$ 685,527	$ 763,335	$ -	$ 844,002	$ 973,630	$ 1,051,432	$ 1,055,161	$ 982,931	$ 931,015
Shalimar	Okaloosa	$ 26,224	$ 29,483	$ 32,737	$ 29,010	$ 35,917	$ 36,364	$ 36,105	$ 33,877	$ 31,590
Valparaiso	Okaloosa	$ 173,338	$ 187,443	$ 206,265	$ 202,699	$ 228,330	$ 246,976	$ 241,216	$ 218,162	$ 208,668
Okeechobee	Okeechobee	$ 310,950	$ 424,690	$ 501,556	$ 475,603	$ 467,830	$ 431,792	$ 424,235	$ 383,620	$ 373,515
Apopka	Orange	$ 2,130,401	$ 2,685,384	$ 2,792,464	$ 2,847,123	$ 3,066,620	$ 3,403,044	$ 3,175,900	$ 2,978,723	$ 2,915,064
Bay Lake	Orange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Belle Isle	Orange	$ -	$ -	$ -	$ -	$ 427	$ -	$ -	$ -	$ -
Eatonville	Orange	$ 210,033	$ 278,943	$ 313,029	$ -	$ 401,774	$ 409,789	$ 388,008	$ 385,866	$ 367,737
Edgewood	Orange	$ -	$ 250,000	$ 228,894	$ 235,534	$ 263,308	$ 272,927	$ 255,265	$ 250,680	$ 234,356
Lake Buena Vista	Orange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Maitland	Orange	$ 1,624,735	$ 2,009,587	$ 2,075,992	$ 1,976,046	$ 2,188,184	$ 2,306,133	$ 2,147,420	$ 2,051,239	$ 1,928,829
Oakland	Orange	$ 98,045	$ -	$ 125,027	$ 117,245	$ 127,515	$ 149,253	$ 138,388	$ 114,914	$ 121,630
Ocoee	Orange	$ 1,704,297	$ 2,028,925	$ 2,129,237	$ 2,288,245	$ 2,340,420	$ 2,470,047	$ 2,282,166	$ 2,155,543	$ 2,037,602
Orlando	Orange	$ 20,686,024	$ 24,339,198	$ 24,909,003	$ 26,008,241	$ 28,066,279	$ 29,623,113	$ 29,800,148	$ 30,607,056	$ 30,316,649
Windermere	Orange	$ 165,571	$ 202,907	$ 213,284	$ 212,929	$ 243,127	$ 268,003	$ 249,753	$ 235,501	$ 172,648
Winter Garden	Orange	$ 1,138,137	$ 1,497,094	$ 1,715,447	$ 1,840,516	$ 2,157,770	$ 2,382,046	$ 2,216,903	$ 2,132,056	$ 1,967,896
Winter Park	Orange	$ 1,639,538	$ 278,153	$ 268,838	$ 244,533	$ 282,228	$ 301,803	$ 277,757	$ 263,156	$ 245,421
Kissimmee	Osceola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Cloud	Osceola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Atlantis	Palm Beach	$ 261,697	$ 309,622	$ 328,950	$ 323,734	$ 329,853	$ 303,194	$ 288,442	$ 286,814	$ 274,271
Belle Glade	Palm Beach	$ 628,762	$ 733,764	$ 804,532	$ 827,035	$ 835,557	$ 764,708	$ 722,271	$ 672,598	$ 664,174
Boca Raton	Palm Beach	$ 8,926,867	$ 11,742,047	$ 11,610,122	$ 11,548,212	$ 11,603,975	$ 10,394,821	$ 10,335,277	$ 9,930,026	$ 9,655,545
Boynton Beach	Palm Beach	$ 3,577,313	$ 4,492,552	$ 4,711,922	$ 4,709,893	$ 4,723,342	$ 4,299,833	$ 4,243,934	$ 4,053,788	$ 4,068,561
Briny Breeze	Palm Beach	$ -	$ -	$ -	$ -	$ 69	$ -	$ -	$ 4,249	$ -
Cloud Lake	Palm Beach	$ -	$ 5,964	$ 6,210	$ 6,067	$ 5,591	$ 5,647	$ 5,496	$ 4,426	$ 4,663
Delray Beach	Palm Beach	$ 3,714,312	$ 4,585,117	$ 4,965,588	$ 4,993,678	$ 4,995,821	$ 4,572,996	$ 4,446,425	$ 4,360,879	$ 4,243,489
Glen Ridge	Palm Beach	$ 13,783	$ 12,375	$ 15,473	$ 13,878	$ 14,659	$ 14,937	$ 13,618	$ 13,180	$ 13,066
Golf	Palm Beach	$ 52,883	$ 58,774	$ 94,722	$ 54,549	$ 74,667	$ 39,711	$ 65,488	$ 63,362	$ 57,341
Greenacres	Palm Beach	$ 1,267,295	$ 1,794,174	$ 1,803,341	$ 1,796,045	$ 1,806,735	$ 1,655,016	$ 1,634,914	$ 1,563,973	$ 1,550,831
Gulf Stream	Palm Beach	$ 102,213	$ 116,090	$ 128,911	$ 126,171	$ 125,957	$ 115,934	$ 117,428	$ 121,950	$ 123,554
Haverhill	Palm Beach	$ 61,748	$ 84,248	$ 83,417	$ 85,056	$ 82,133	$ 77,986	$ 76,763	$ 74,874	$ 73,493
Highland Beach	Palm Beach	$ 386,038	$ 453,670	$ 467,708	$ 497,727	$ 489,055	$ -	$ -	$ 411,434	$ 409,721
Hypoluxo	Palm Beach	$ 25,799	$ 99,893	$ 35,309	$ 32,150	$ 35,537	$ 31,959	$ 29,431	$ 34,252	$ 36,058
Juno Beach	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jupiter	Palm Beach	$ 3,277,836	$ 3,988,849	$ 4,284,216	$ 4,605,769	$ 4,552,852	$ 4,250,214	$ 4,174,546	$ 4,099,937	$ 4,003,956
Jupiter Inlet Colony	Palm Beach	$ 36,656	$ 37,862	$ 37,074	$ 37,068	$ 36,927	$ 36,462	$ 34,901	$ 29,798	$ 36,177
Lake Clarke Shores	Palm Beach	$ 165,230	$ 197,576	$ 200,074	$ 197,772	$ 195,892	$ 205,476	$ 185,253	$ 178,610	$ 167,987
Lake Park	Palm Beach	$ 492,627	$ 600,953	$ 604,641	$ 609,578	$ 599,961	$ 547,504	$ 546,589	$ 521,720	$ 464,734
Lake Worth	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ 322,242	$ 348,880	$ 379,622	$ 352,489
Lantana	Palm Beach	$ 567,405	$ 704,607	$ 760,523	$ 788,261	$ 759,640	$ 679,844	$ 673,526	$ 628,615	$ 610,311
Loxahatchee Groves	Palm Beach	$ -	$ -	$ 65,728	$ 218,236	$ 224,342	$ 203,552	$ 196,426	$ 188,222	$ 185,002
Manalapan	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mangonia Park	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ 174,967	$ 172,849	$ 168,009	$ 171,420
North Palm Beach	Palm Beach	$ 678,543	$ 932,476	$ 967,104	$ 975,594	$ 999,894	$ 924,671	$ 904,190	$ 858,495	$ 849,522
Ocean Ridge	Palm Beach	$ 122,218	$ 140,729	$ 173,919	$ 173,034	$ 179,977	$ 166,934	$ 162,832	$ 155,573	$ 151,526
Pahokee	Palm Beach	$ 213,308	$ 237,524	$ 250,828	$ 235,782	$ 238,150	$ 215,575	$ 214,010	$ 200,583	$ 185,622
Palm Beach	Palm Beach	$ 1,758,406	$ 2,146,494	$ 2,244,536	$ 2,217,498	$ 2,225,166	$ 1,992,824	$ 2,060,500	$ 1,900,717	$ 1,872,920
Palm Beach Gardens	Palm Beach	$ 3,773,233	$ 4,817,152	$ 5,163,100	$ 5,259,924	$ 5,353,322	$ 4,763,392	$ 4,674,054	$ 5,059,328	$ 4,854,693
Palm Beach Shores	Palm Beach	$ 127,340	$ 150,100	$ 171,289	$ 171,101	$ 171,448	$ 159,908	$ 152,925	$ 151,302	$ 144,636
Palm Springs	Palm Beach	$ 540,311	$ 780,483	$ 856,523	$ 923,506	$ 958,475	$ 917,182	$ 901,726	$ 898,301	$ 901,973
Riviera Beach	Palm Beach	$ 786,362	$ 1,627,858	$ 1,861,022	$ -	$ 2,330,697	$ 1,470,445	$ 2,547,274	$ 2,467,133	$ 2,493,132
Royal Palm Beach	Palm Beach	$ 1,554,168	$ 1,995,325	$ 2,131,512	$ 2,152,419	$ 2,209,219	$ 2,017,142	$ 1,958,655	$ 1,867,777	$ 1,837,769
South Bay	Palm Beach	$ 181,613	$ -	$ 219,633	$ 212,148	$ 214,368	$ 223,331	$ 184,067	$ 175,312	$ 169,221
South Palm Beach	Palm Beach	$ 90,840	$ 100,938	$ 103,285	$ 96,046	$ 103,353	$ 114,651	$ 94,939	$ 93,415	$ 84,226
Tequesta	Palm Beach	$ 363,808	$ 405,774	$ 444,419	$ 462,296	$ 466,541	$ 435,766	$ 412,441	$ 393,734	$ 380,160
Wellington	Palm Beach	$ 2,744,351	$ 3,430,912	$ 3,512,575	$ 3,492,742	$ 3,594,701	$ 3,298,051	$ 3,266,018	$ 3,157,328	$ 3,205,140
West Palm Beach	Palm Beach	$ 7,068,140	$ 8,717,702	$ 8,598,349	$ 8,387,637	$ 8,220,306	$ 7,849,917	$ 7,367,062	$ 8,068,300	$ 7,922,637
Dade City	Pasco	$ 361,118	$ 413,416	$ 446,367	$ 434,134	$ 461,110	$ 625,560	$ 626,496	$ 595,133	$ 573,725
New Port Richey	Pasco	$ 1,016,715	$ 1,204,290	$ 1,213,353	$ 1,143,529	$ 1,274,827	$ 1,351,763	$ 1,234,178	$ 1,154,551	$ 1,092,832
Port Richey	Pasco	$ 265,782	$ 320,804	$ 328,572	$ 308,766	$ 331,686	$ 347,590	$ 313,410	$ 302,754	$ 326,515
San Antonio	Pasco	$ 63,221	$ 60,966	$ 64,530	$ 65,802	$ 69,447	$ 66,435	$ 65,590	$ 59,739	$ 63,906

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
St. Leo	Pasco	$ 66,472	$ 69,590	$ 78,167	$ 85,611	$ 91,209	$ 90,789	$ 93,591	$ 85,973	$ 84,618
Zephyrhills	Pasco	$ 1,010,530	$ 1,239,299	$ 1,301,586	$ 1,265,283	$ 1,420,062	$ 1,450,421	$ 1,359,544	$ 1,325,328	$ 1,277,350
Belleair	Pinellas	$ -	$ 791,944	$ 386,920	$ -	$ -	$ -	$ -	$ -	$ 339,314
Belleair Beach	Pinellas	$ 123,631	$ 143,514	$ 145,305	$ 142,618	$ 158,680	$ 174,310	$ 160,593	$ 148,629	$ 144,505
Belleair Bluffs	Pinellas	$ 157,190	$ 180,929	$ 184,157	$ 182,056	$ 201,263	$ 213,657	$ 197,113	$ 186,713	$ 180,767
Belleair Shore	Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Clearwater	Pinellas	$ 7,572,305	$ 8,724,750	$ 8,867,217	$ 8,633,587	$ 9,606,151	$ 9,970,713	$ 9,423,572	$ 9,039,274	$ 8,594,708
Dunedin	Pinellas	$ 2,125,645	$ 2,505,492	$ 2,497,847	$ 2,399,525	$ 2,697,564	$ 2,843,575	$ 2,616,312	$ 2,450,827	$ 2,297,545
Gulfport	Pinellas	$ 619,799	$ 716,025	$ 710,175	$ 706,680	$ 766,603	$ 843,095	$ 772,556	$ 728,839	$ 697,350
Indian Rocks Beach	Pinellas	$ 330,690	$ 383,417	$ 388,796	$ 375,420	$ 421,744	$ 448,273	$ 415,445	$ 395,382	$ 379,075
Indian Shores	Pinellas	$ 185,193	$ 217,342	$ 216,767	$ 220,289	$ 259,681	$ 269,597	$ 246,648	$ 237,607	$ 226,333
Kenneth City	Pinellas	$ 250,640	$ 284,039	$ 284,388	$ 272,912	$ 303,124	$ 323,303	$ -	$ -	$ 267,280
Largo	Pinellas	$ 4,732,653	$ 5,650,916	$ 5,703,179	$ 5,596,824	$ 6,087,481	$ 6,411,590	$ 5,903,509	$ 5,573,591	$ 5,434,523
Madeira Beach	Pinellas	$ 396,627	$ 458,107	$ 472,695	$ 463,715	$ 521,694	$ 555,870	$ 512,342	$ 498,580	$ 471,972
North Redington Beach	Pinellas	$ 119,487	$ 141,087	$ 145,334	$ 144,982	$ 162,961	$ 171,742	$ 157,486	$ 151,281	$ 145,898
Oldsmar	Pinellas	$ 1,159,864	$ 1,267,464	$ 1,380,863	$ 1,389,900	$ 1,568,598	$ 1,495,433	$ 1,421,900	$ 1,360,249	$ 1,308,911
Pinellas Park	Pinellas	$ 3,592,319	$ 4,301,521	$ 4,382,041	$ 4,275,861	$ 4,629,918	$ 4,859,474	$ 4,459,365	$ 4,429,739	$ 4,204,620
Redington Beach	Pinellas	$ 92,701	$ 108,660	$ 109,277	$ 109,464	$ 124,524	$ 132,818	$ 122,596	$ 112,331	$ 109,406
Redington Shores	Pinellas	$ 122,227	$ 161,167	$ 173,422	$ 180,016	$ -	$ -	$ -	$ -	$ -
Safety Harbor	Pinellas	$ 1,145,076	$ 1,363,738	$ 1,384,163	$ 1,357,917	$ 1,488,509	$ 1,552,134	$ 1,397,936	$ 1,366,752	$ 1,287,457
Seminole	Pinellas	$ 1,132,351	$ 1,340,149	$ 1,365,355	$ 1,335,388	$ 1,466,842	$ 1,513,548	$ 1,390,924	$ 1,333,793	$ 1,260,575
South Pasadena	Pinellas	$ 389,384	$ 441,736	$ 448,343	$ 433,306	$ 468,157	$ 490,319	$ 459,341	$ 443,319	$ 426,267
St. Pete Beach	Pinellas	$ 939,945	$ 1,096,959	$ 1,104,115	$ 1,078,827	$ 1,185,052	$ 1,260,830	$ 1,168,407	$ 1,128,415	$ 1,067,548
St. Petersburg	Pinellas	$ 15,815,954	$ 18,440,168	$ 18,545,819	$ 18,196,871	$ 20,211,279	$ -	$ 19,684,895	$ 18,940,068	$ 18,126,537
Tarpon Springs	Pinellas	$ 1,400,870	$ 1,649,244	$ 1,640,667	$ 1,608,984	$ 1,754,810	$ 1,867,360	$ 1,691,774	$ 1,578,758	$ 1,535,574
Treasure Island	Pinellas	$ 591,418	$ 640,887	$ 648,173	$ 640,658	$ 730,141	$ 769,614	$ 723,927	$ 693,506	$ 660,135
Auburndale	Polk	$ 602,695	$ 707,733	$ 995,737	$ 956,741	$ 998,277	$ 1,023,878	$ 918,107	$ 897,026	$ 868,885
Bartow	Polk	$ 35,676	$ 98,354	$ 107,532	$ 115,784	$ 144,620	$ 140,007	$ 143,205	$ 153,497	$ 127,727
Davenport	Polk	$ 144,001	$ 171,662	$ 185,957	$ 231,053	$ 259,456	$ 273,754	$ 257,040	$ 255,465	$ 245,168
Dundee	Polk	$ 182,858	$ 225,254	$ 236,798	$ 213,269	$ 250,740	$ 261,488	$ 239,889	$ 216,926	$ 224,964
Eagle Lake	Polk	$ 98,036	$ 110,646	$ 125,687	$ 126,299	$ 140,948	$ 146,841	$ 135,229	$ 133,297	$ 124,117
Fort Meade	Polk	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Frostproof	Polk	$ 236,759	$ 303,043	$ 283,001	$ 204,585	$ 238,209	$ 282,395	$ 235,388	$ 220,301	$ 210,308
Haines City	Polk	$ 874,615	$ 1,166,386	$ 1,350,825	$ 1,348,220	$ 1,680,164	$ 1,805,492	$ 1,692,465	$ 1,671,100	$ 1,595,278
Highland Park	Polk	$ 11,719	$ 13,217	$ 12,718	$ 12,498	$ 14,044	$ 14,804	$ 13,532	$ 12,819	$ 12,212
Hillcrest Heights	Polk	$ 12,573	$ 15,046	$ 15,137	$ 14,349	$ 15,664	$ 17,054	$ 15,947	$ 14,519	$ 13,912
Lake Alfred	Polk	$ 172,041	$ 197,488	$ 251,012	$ 260,197	$ 287,299	$ 287,578	$ 259,539	$ 244,282	$ 234,530
Lake Hamilton	Polk	$ 87,972	$ -	$ 124,718	$ 124,739	$ 98,723	$ 96,273	$ 128,526	$ 99,143	$ 100,866
Lake Wales	Polk	$ 864,226	$ 1,062,860	$ 1,092,301	$ 1,069,959	$ 1,151,213	$ 1,233,833	$ 1,127,705	$ 1,082,129	$ 981,696
Lakeland	Polk	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mulberry	Polk	$ -	$ -	$ -	$ -	$ -	$ 435,642	$ 406,332	$ 359,535	$ 344,368
Polk City	Polk	$ 61,080	$ 67,728	$ 73,005	$ 68,170	$ 72,604	$ 72,171	$ 65,845	$ 57,332	$ 53,795
Winter Haven	Polk	$ 1,938,565	$ 2,781,231	$ 2,991,273	$ 3,051,713	$ 3,215,035	$ 3,248,053	$ 2,994,236	$ 2,908,551	$ 2,847,840
Crescent City	Putnam	$ 79,447	$ 102,909	$ 108,771	$ 102,486	$ 105,707	$ 95,147	$ 104,415	$ 101,609	$ 99,399
Interlachen	Putnam	$ 68,050	$ 93,311	$ 97,712	$ 99,225	$ 116,871	$ 88,394	$ 89,796	$ 99,837	$ 93,955
Palatka	Putnam	$ 684,678	$ 911,188	$ 915,447	$ -	$ -	$ -	$ 886,166	$ 662,190	$ 904,958
Pomona Park	Putnam	$ 27,128	$ 40,425	$ 41,149	$ 39,053	$ 41,643	$ 38,479	$ 38,528	$ 34,221	$ 33,784
Welaka	Putnam	$ 29,240	$ 35,985	$ 40,954	$ -	$ -	$ -	$ -	$ 39,571	$ 38,771
Gulf Breeze	Santa Rosa	$ 211,325	$ 240,992	$ 279,313	$ 243,849	$ 293,431	$ 364,912	$ 334,218	$ 305,448	$ 288,767
Jay	Santa Rosa	$ 37,886	$ 42,080	$ 43,572	$ 41,059	$ 52,134	$ 48,884	$ 47,777	$ 47,977	$ 49,546
Milton	Santa Rosa	$ 804,482	$ 492,232	$ 545,828	$ 549,504	$ 627,889	$ 669,429	$ 696,880	$ 608,794	$ 569,689

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
North Port	Sarasota	$ 1,695,328	$ 2,332,266	$ 2,622,881	$ 2,746,028	$ 2,856,743	$ 2,637,138	$ 2,654,895	$ 2,521,691	$ 2,549,869
Sarasota	Sarasota	$ 4,267,043	$ 5,277,456	$ 5,413,205	$ 5,075,916	$ 5,158,391	$ 4,760,356	$ 4,881,247	$ 4,488,238	$ 4,360,645
Venice	Sarasota	$ 1,437,967	$ 1,700,643	$ 1,889,769	$ 2,048,209	$ -	$ 1,766,902	$ 1,923,226	$ 1,671,449	$ 1,667,793
Altamonte Springs	Seminole	$ 3,182,984	$ 3,745,411	$ 3,812,356	$ 3,701,475	$ 4,043,506	$ 4,135,324	$ 3,829,531	$ 3,723,746	$ 3,525,885
Casselberry	Seminole	$ 1,453,522	$ 1,704,793	$ 1,701,686	$ 1,674,187	$ 1,774,061	$ 1,932,615	$ 1,762,461	$ 1,638,341	$ 1,606,416
Lake Mary	Seminole	$ 1,341,599	$ 1,678,032	$ 1,740,485	$ 1,722,653	$ 2,026,466	$ 2,009,483	$ 1,869,649	$ 1,770,383	$ 1,663,649
Longwood	Seminole	$ 1,065,866	$ 1,275,614	$ 1,327,796	$ 1,281,976	$ 1,373,822	$ 1,406,640	$ 1,310,637	$ 1,244,448	$ 1,136,706
Oviedo	Seminole	$ 1,685,862	$ 2,061,952	$ 2,126,951	$ 2,106,098	$ 2,322,719	$ 2,416,073	$ 2,185,142	$ 2,094,897	$ 2,013,511
Sanford	Seminole	$ 2,765,533	$ 3,598,576	$ 3,542,532	$ 3,421,078	$ 4,270,266	$ 3,892,899	$ 4,055,362	$ 3,452,242	$ 3,476,798
Winter Springs	Seminole	$ 1,436,996	$ 1,775,460	$ 1,759,245	$ 1,748,477	$ 1,823,706	$ 2,173,849	$ 1,873,785	$ 1,748,214	$ 1,541,741
Hastings	St. Johns	$ -	$ -	$ -	$ -	$ 43,630	$ 40,713	$ 39,977	$ 36,675	$ 35,825
St. Augustine	St. Johns	$ 1,102,834	$ 1,128,388	$ 1,377,959	$ 1,110,025	$ 1,296,215	$ 1,220,699	$ 1,211,390	$ 1,125,547	$ 1,125,547
St. Augustine Beach	St. Johns	$ 356,662	$ 432,051	$ 441,490	$ 432,761	$ 450,256	$ 416,651	$ -	$ 378,445	$ 383,647
Fort Pierce	St. Lucie	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Port St. Lucie	St. Lucie	$ 5,451,820	$ 7,370,278	$ 8,176,844	$ 8,363,948	$ 8,627,252	$ 7,987,044	$ 7,656,194	$ 8,161,246	$ 7,755,163
St. Lucie Village	St. Lucie	$ 43,270	$ -	$ 56,760	$ -	$ -	$ -	$ -	$ -	$ -
Bushnell	Sumter	$ 104,225	$ 135,330	$ 136,726	$ 140,713	$ 170,630	$ 169,044	$ 162,544	$ 153,767	$ 149,964
Center Hill	Sumter	$ 33,852	$ 35,855	$ 35,221	$ 33,591	$ 40,500	$ 47,260	$ 42,084	$ 59,917	$ 112,239
Coleman	Sumter	$ 29,426	$ 34,877	$ 34,207	$ 32,643	$ 37,768	$ 39,853	$ 37,161	$ 33,774	$ 32,064
Webster	Sumter	$ 36,365	$ -	$ 42,790	$ -	$ -	$ -	$ -	$ -	NR
Wildwood	Sumter	$ 262,759	$ 413,205	$ 466,337	$ -	$ -	$ 530,313	$ 597,810	$ 573,140	$ 621,148
Branford	Suwannee	$ 91,305	$ 53,337	$ 55,409	$ 52,741	$ 58,341	$ 63,464	$ 60,518	$ 113,535	$ 60,407
Live Oak	Suwannee	$ 380,980	$ 458,927	$ 497,592	$ 504,508	$ 509,338	$ 473,128	$ 532,787	$ 506,808	$ 484,462
Perry	Taylor	$ 467,275	$ 560,200	$ 595,585	$ 619,089	$ 615,194	$ 674,009	$ 624,507	$ 575,582	$ 555,693
Lake Butler	Union	$ 109,011	$ 132,329	$ 139,336	$ -	$ 146,726	$ 147,801	$ 136,064	$ 123,170	$ 121,511
Raiford	Union	$ 9,095	$ 10,663	$ 11,345	$ 10,921	$ 10,449	$ 10,512	$ 10,705	$ 10,407	$ 19,072
Worthington Springs	Union	$ -	$ 19,948	$ 20,818	$ 21,570	$ 21,110	$ 23,578	$ 23,146	$ 22,198	$ 21,484
Daytona Beach	Volusia	$ 5,154,580	$ 6,265,693	$ 6,223,343	$ 6,200,040	$ 6,364,012	$ 5,703,685	$ 5,610,973	$ 5,207,599	$ 5,176,341
Daytona Beach Shores	Volusia	$ 517,000	$ 625,000	$ 675,399	$ 724,482	$ 662,530	$ 600,000	$ 570,000	$ 601,000	$ 538,000
DeBary	Volusia	$ -	$ -	$ 471,557	$ 721,497	$ 816,271	$ 869,091	$ 809,201	$ 733,119	$ 705,575
DeLand	Volusia	$ 1,810,686	$ 2,306,634	$ 2,397,041	$ 2,336,573	$ 2,596,915	$ 2,723,411	$ 2,495,352	$ 2,402,218	$ 2,283,921
Deltona	Volusia	$ 3,115,972	$ 3,883,319	$ 3,730,656	$ 3,732,717	$ 3,966,949	$ 4,052,016	$ 3,892,925	$ 3,412,062	$ 3,405,299
Edgewater	Volusia	$ 770,876	$ 969,336	$ 1,019,970	$ 905,599	$ 1,014,785	$ 935,435	$ 889,634	$ 819,855	$ 891,558
Holly Hill	Volusia	$ 703,538	$ 822,824	$ 846,168	$ 844,646	$ 838,839	$ 754,965	$ 791,706	$ 705,238	$ 708,344
Lake Helen	Volusia	$ 106,215	$ 128,740	$ 130,872	$ 127,285	$ 147,285	$ 158,574	$ 147,055	$ 136,899	$ 134,735
New Smyrna Beach	Volusia	$ 2,087,724	$ 2,490,845	$ 2,802,272	$ 2,763,854	$ 2,758,741	$ 2,972,858	$ 2,637,346	$ 2,482,873	$ 2,303,525
Oak Hill	Volusia	$ 72,507	$ 92,737	$ 94,865	$ 92,653	$ 93,479	$ 87,025	$ 85,189	$ 78,794	$ 81,374
Orange City	Volusia	$ 734,893	$ 909,839	$ 952,424	$ 958,850	$ 1,107,942	$ 1,169,914	$ 1,125,485	$ 1,094,789	$ 1,041,469
Ormond Beach	Volusia	$ 2,631,000	$ 3,189,000	$ 3,204,000	$ 3,125,000	$ 3,183,000	$ 3,131,000	$ 2,949,000	$ 2,679,000	$ 2,669,000
Pierson	Volusia	$ 72,808	$ 87,419	$ 88,798	$ 87,637	$ 97,004	$ 103,620	$ 96,325	$ 87,829	$ 84,514
Ponce Inlet	Volusia	$ 216,623	$ 255,806	$ 263,249	$ 254,508	$ 267,135	$ 250,319	$ 239,248	$ 220,402	$ 215,724
Port Orange	Volusia	$ 2,558,130	$ 3,145,480	$ -	$ 3,165,772	$ 3,369,242	$ 3,118,664	$ 3,128,578	$ 2,864,263	$ 2,893,287
South Daytona	Volusia	$ 615,078	$ 744,225	$ 738,459	$ 723,698	$ 709,452	$ 650,741	$ 635,672	$ 580,572	$ 588,317
Sopchoppy	Wakulla	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,131	$ 24,424	$ 23,826
St. Marks	Wakulla	$ 19,088	$ 23,324	$ 13,897	$ 25,082	$ 26,327	$ 32,764	$ 26,676	$ 25,542	$ 26,110
DeFuniak Springs	Walton	$ 181,919	$ 203,261	$ 224,490	$ 226,941	$ 274,447	$ 282,737	$ 279,918	$ 250,581	$ 231,563
Freeport	Walton	$ 46,331	$ 50,877	$ 65,360	$ 73,518	$ 85,544	$ 83,795	$ 83,917	$ 89,064	$ 90,723
Paxton	Walton	$ 15,520	$ 17,805	$ 19,156	$ -	$ 25,047	$ 27,144	$ 25,596	$ 21,159	$ 21,158
Caryville	Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,990	$ 6,176	NR
Chipley	Washington	$ 206,310	$ 228,151	$ 246,185	$ 246,950	$ 279,070	$ 309,667	$ 313,300	$ 273,275	$ 243,218
Ebro	Washington	$ 17,529	$ 20,293	$ 20,491	$ 23,766	$ -	$ -	$ -	$ -	$ -

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Vernon	Washington	$ 22,200	$ 26,033	$ 28,476	$ 28,487	$ 32,859	$ 35,712	$ 36,882	$ 32,525	$ 29,873
Wausau	Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Municipal Franchise Fees-Electricity Totals		**$ 434,429,008**	**$ 514,540,702**	**$ 546,883,232**	**$ 546,658,421**	**$ 600,243,133**	**$ 565,453,359**	**$ 571,030,032**	**$ 563,206,940**	**$ 546,561,653**
% Change		**-**	**18.4%**	**6.3%**	**0.0%**	**9.8%**	**-5.8%**	**1.0%**	**-1.4%**	**-3.0%**
# Reporting		**340**	**335**	**344**	**331**	**339**	**344**	**345**	**349**	**342**
Total Municipal Franchise Fees		**$ 541,407,060**	**$ 633,075,955**	**$ 669,073,212**	**$ 673,918,453**	**$ 717,295,819**	**$ 705,492,123**	**$ 713,743,133**	**$ 691,485,849**	**$ 656,455,841**
% Change		**-**	**16.9%**	**5.7%**	**0.7%**	**6.4%**	**-1.6%**	**1.2%**	**-3.1%**	**-5.1%**
Electricity Fees as % of All Fees		**80.2%**	**81.3%**	**81.7%**	**81.1%**	**83.7%**	**80.2%**	**80.0%**	**81.4%**	**83.3%**

Notes:
1) This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 323.100 - Franchise Fee - Electricity and 323.XXX - Franchise Fees.
2) NR indicates those municipalities for which FY 2012-13 revenue data are not yet available. The FY 2012-13 account totals include the reported revenues of all Florida municipalities, except for the nine municipalities of Arcadia, Astatula, Caryville, Gretna, Groveland, Hampton, Quincy, Springfield, and Webster. This file will be updated in the future as these data become available.

Data Source: Florida Department of Financial Services.

Public Service Tax

Sections 166.231-.235, Florida Statutes

Municipalities and charter counties may levy by ordinance a public service tax on the purchase of electricity, metered natural gas, liquefied petroleum gas either metered or bottled, manufactured gas either metered or bottled, and water service.[1] The tax is levied only upon purchases within the municipality or within the charter county's unincorporated area and cannot exceed 10 percent of the payments received by the seller of the taxable item. Services competitive with those listed above, as defined by ordinance, can be taxed on a comparable base at the same rates; however, the tax rate on fuel oil cannot exceed 4 cents per gallon.[2] The tax proceeds are considered general revenue for the municipality or charter county.

All municipalities are eligible to levy the tax within the area of its tax jurisdiction. In addition, municipalities imposing the tax on cable television service, as of May 4, 1977, may continue the tax levy in order to satisfy debt obligations incurred prior to that date. By virtue of a number of legal rulings in Florida case law, a charter county may levy the tax within the unincorporated area. For example, the Florida Supreme Court ruled in 1972 that charter counties, unless specifically precluded by general or special law, could impose by ordinance any tax in the area of its tax jurisdiction that a municipality could impose.[3] In 1994, the Court held that Orange County could levy a public service tax without specific statutory authority to do so.[4]

The tax is collected by the seller of the taxable item from the purchaser at the time of payment.[5] At the discretion of the local taxing authority, the tax may be levied on a physical unit basis. Using this basis, the tax is levied as follows: electricity, number of kilowatt hours purchased; metered or bottled gas, number of cubic feet purchased; fuel oil and kerosene, number of gallons purchased; and water service, number of gallons purchased.[6] A number of tax exemptions are specified in law.[7]

A tax levy is adopted by ordinance, and the effective date of every tax levy or repeal must be the beginning of a subsequent calendar quarter: January 1st, April 1st, July 1st, or October 1st. The taxing authority must notify the Department of Revenue (DOR) of a tax levy adoption or repeal at least 120 days before its effective date. Such notification must be furnished on a form prescribed by the DOR and specify the services taxed, the tax rate applied to each service, and the effective date of the levy or repeal as well as other additional information.[8]

The seller of the service remits the taxes collected to the governing body in the manner prescribed by ordinance.[9] The tax proceeds are considered general revenue for the municipality or charter county. As previously mentioned, taxing authorities are required to furnish information to the DOR and the Department maintains an online database that can be searched or downloaded.[10]

Summaries of prior years' revenues reported by county and municipal governments are available.[11]

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1. Section 166.231(1), F.S.
2. Section 166.231(2), F.S.
3. Volusia County vs. Dickinson, 269 So.2d 9 (Fla. 1972).
4. McLeod vs. Orange County, 645 So.2d 411 (Fla. 1994).
5. Section 166.231(7), F.S.
6. Section 166.232, F.S.
7. Section 166.231(3)-(6) and (8), F.S.
8. Section 166.233(2), F.S.
9. Section 166.231(7), F.S.
10. http://dor.myflorida.com/dor/governments/mpst/
11. http://edr.state.fl.us/Content/local-government/data/data-a-to-z/index.cfm

Reported Charter County and Municipal Government Public Service Tax-Electricity Revenues
Local Fiscal Years 2004-05 to 2012-13

Charter County Governments

Local Fiscal Year	# Reporting Public Service Tax-Electricity Revenue	Public Service Tax-Electricity Revenue	Total Public Service Tax Revenue	Public Service Tax-Electricity as % of Total Public Serv. Tax	Total Revenue from All Accounts	Public Service Tax-Electricity as % of Total Revenue
2012-13	12	$ 224,108,346	$ 255,773,406	87.6%	$ 27,804,976,718	0.8%
2011-12	12	$ 211,481,130	$ 244,184,342	86.6%	$ 27,047,223,815	0.8%
2010-11	11	$ 217,814,874	$ 251,822,146	86.5%	$ 27,965,830,439	0.8%
2009-10	11	$ 244,692,391	$ 281,154,266	87.0%	$ 28,575,074,348	0.9%
2008-09	11	$ 221,229,527	$ 254,222,270	87.0%	$ 31,146,892,897	0.7%
2007-08	11	$ 225,493,666	$ 274,245,712	82.2%	$ 32,366,257,060	0.7%
2006-07	12	$ 237,834,185	$ 292,209,635	81.4%	-	-
2005-06	11	$ 220,842,424	$ 272,131,634	81.2%	-	-
2004-05	11	$ 204,132,618	$ 250,943,479	81.3%	-	-

Municipal Governments

Local Fiscal Year	# Reporting Public Service Tax-Electricity Revenue	Public Service Tax-Electricity Revenue	Total Public Service Tax Revenue	Public Service Tax-Electricity as % of Total Public Serv. Tax	Total Revenue from All Accounts	Public Service Tax-Electricity as % of Total Revenue
2012-13 **	327	$ 686,333,857	$ 864,080,636	79.4%	$ 31,927,999,565	2.1%
2011-12	334	$ 666,317,873	$ 837,408,227	79.6%	$ 32,060,876,417	2.1%
2010-11	335	$ 671,200,686	$ 830,044,048	80.9%	$ 28,173,312,741	2.4%
2009-10	328	$ 668,376,661	$ 948,885,749	70.4%	$ 30,459,315,301	2.2%
2008-09	325	$ 606,134,061	$ 912,265,351	66.4%	$ 28,291,875,774	2.1%
2007-08	318	$ 581,414,018	$ 829,153,910	70.1%	-	-
2006-07	318	$ 560,530,030	$ 808,793,559	69.3%	-	-
2005-06	308	$ 522,270,643	$ 772,981,528	67.6%	-	-
2004-05	305	$ 505,856,228	$ 741,201,140	68.2%	-	-

Combined Total: Charter County and Municipal Governments

Local Fiscal Year	# Reporting Public Service Tax-Electricity Revenue	Public Service Tax-Electricity Revenue
2012-13 **	339	$ 910,442,203
2011-12	346	$ 877,799,003
2010-11	346	$ 889,015,560
2009-10	339	$ 913,069,052
2008-09	336	$ 827,363,588
2007-08	329	$ 806,907,684
2006-07	330	$ 798,364,215
2005-06	319	$ 743,113,067
2004-05	316	$ 709,988,846

Notes:
1) This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 314.100 - Utility Service Tax-Electricity.
2) FY 2012-13 Annual Financial Reports for nine municipalities have not yet been submitted to or certified by the Department of Financial Services. Consequently, the 2012-13 revenue figures are not yet final, and the municipal and combined totals are subject to future revision.

Source: EDR staff compilation of Annual Financial Report (AFR) data obtained from the Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Government.

Summary of Reported Charter County Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Charter County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Alachua - charter adopted in 1987	$ 4,964,976	$ 5,493,288	$ 5,703,837	$ 6,013,936	$ 5,948,038	$ 6,555,386	$ 6,581,093	$ 6,090,689	$ 6,083,440
Brevard - charter adopted in 1994	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Broward - charter adopted in 1975	$ 3,383,000	$ 2,692,000	$ 1,136,000	$ 789,000	$ 762,000	$ 821,000	$ 796,000	$ 800,000	$ 874,000
Charlotte - charter adopted in 1986	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Clay - charter adopted in 1991	$ 2,509,546	$ 3,015,201	$ 2,992,327	$ 2,825,032	$ 2,922,524	$ 3,420,107	$ 3,594,741	$ 3,245,305	$ 3,178,068
Columbia - charter adopted in 2002	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Duval - charter adopted in 1968	Refer to the separate municipal table for the consolidated City of Jacksonville/Duval County totals.								
Hillsborough - charter adopted in 1983	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lee - charter adopted in 1996	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Leon - charter adopted in 2002	$ 3,499,443	$ 3,910,747	$ 4,164,153	$ 4,500,799	$ 4,670,579	$ 4,897,113	$ 4,955,507	$ 5,819,459	$ 5,033,573
Miami-Dade - charter adopted in 1957	$ 56,441,665	$ 63,287,321	$ 59,906,815	$ 62,688,547	$ 57,994,144	$ 62,519,724	$ 65,007,358	$ 64,927,166	$ 70,623,468
Orange - charter adopted in 1987	$ 42,443,781	$ 45,479,490	$ 47,168,065	$ 48,568,837	$ 50,185,652	$ 58,786,397	$ 56,510,197	$ 52,525,005	$ 55,737,049
Osceola - charter adopted in 1992	$ 7,711,380	$ 8,697,086	$ 8,872,644	$ 9,085,078	$ 9,363,124	$ 10,487,000	$ 11,666,000	$ 10,654,000	$ 11,345,054
Palm Beach - charter adopted in 1985	$ 55,852,179	$ 56,212,835	$ 58,182,735	$ 58,336,517	$ 55,037,606	$ 58,278,194	$ 32,121,628	$ 31,919,775	$ 33,944,905
Pinellas - charter adopted in 1980	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Polk - charter adopted in 1998	$ 17,296,429	$ 21,442,989	$ 21,433,098	$ 22,183,329	$ 23,476,400	$ 26,258,847	$ 24,648,508	$ 23,761,791	$ 24,509,459
Sarasota - charter adopted in 1971	$ -	$ -	$ 17,752,108	$ -	$ -	$ -	$ -	$ -	$ -
Seminole - charter adopted in 1989	$ 4,069,054	$ 4,337,460	$ 4,340,795	$ 4,330,234	$ 4,441,023	$ 5,310,617	$ 4,947,346	$ 4,480,029	$ 4,789,593
Volusia - charter adopted in 1971	$ 5,961,165	$ 6,274,007	$ 6,181,608	$ 6,172,357	$ 6,428,437	$ 7,358,006	$ 6,986,496	$ 6,463,405	$ 6,902,123
Wakulla - charter adopted in 2008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 794,506	$ 1,087,614
Charter County PST-Electricity Totals	**$ 204,132,618**	**$ 220,842,424**	**$ 237,834,185**	**$ 225,493,666**	**$ 221,229,527**	**$ 244,692,391**	**$ 217,814,874**	**$ 211,481,130**	**$ 224,108,346**
% Change	**-**	**8.2%**	**7.7%**	**-5.2%**	**-1.9%**	**10.6%**	**-11.0%**	**-2.9%**	**6.0%**
# Reporting	**11**	**11**	**12**	**11**	**11**	**11**	**11**	**12**	**12**
Total Charter County Public Service Taxes	**$ 250,943,479**	**$ 272,131,634**	**$ 292,209,635**	**$ 274,245,712**	**$ 254,222,270**	**$ 281,154,266**	**$ 251,822,146**	**$ 244,184,342**	**$ 255,773,406**
% Change	**-**	**8.4%**	**7.4%**	**-6.1%**	**-7.3%**	**10.6%**	**-10.4%**	**-3.0%**	**4.7%**
Electricity PST as % of All PST	**81.3%**	**81.2%**	**81.4%**	**82.2%**	**87.0%**	**87.0%**	**86.5%**	**86.6%**	**87.6%**

Notes:

1) Currently, there are 20 charter counties in Florida.

2) This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 314.XXX - Utility Services Taxes.

Data Source: Florida Department of Financial Services.

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Alachua	Alachua	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Archer	Alachua	$ 58,423	$ -	$ -	$ 14,520	$ 13,995	$ 79,149	$ 76,205	$ 69,488	$ 73,100
Gainesville	Alachua	$ 5,227,810	$ 5,419,732	$ 6,047,469	$ 7,246,954	$ 7,196,428	$ 8,458,312	$ 8,734,265	$ 8,336,629	$ 8,406,996
Hawthorne	Alachua	$ 65,465	$ 69,390	$ 65,855	$ 69,427	$ 79,927	$ 89,629	$ 86,815	$ 82,358	$ 84,758
High Springs	Alachua	$ -	$ 217,003	$ 247,618	$ 249,268	$ 266,325	$ 308,365	$ 294,411	$ 270,770	$ -
La Crosse	Alachua	$ 13,122	$ 13,804	$ 13,946	$ -	$ -	$ 9,605	$ 16,693	$ 9,412	$ 9,018
Micanopy	Alachua	$ 33,349	$ 34,166	$ 33,986	$ 34,027	$ 36,826	$ 44,938	$ 40,207	$ 34,311	$ 38,347
Newberry	Alachua	$ 205,100	$ 268,662	$ 275,437	$ 222,556	$ 190,214	$ 203,549	$ 189,522	$ 189,590	$ 187,990
Waldo	Alachua	$ -	$ 10,108	$ -	$ 116,699	$ 66,992	$ 59,504	$ 70,083	$ 59,859	$ 116,354
Glen St. Mary	Baker	$ -	$ 16,066	$ 30,021	$ 27,991	$ 33,865	$ 32,249	$ 33,196	$ 29,084	$ 31,371
Macclenny	Baker	$ -	$ -	$ -	$ 360,570	$ 409,269	$ 426,387	$ 424,378	$ 413,067	$ 428,975
Callaway	Bay	$ 717,917	$ 743,724	$ 749,924	$ 748,925	$ 749,711	$ 842,364	$ 828,560	$ 801,160	$ 818,126
Lynn Haven	Bay	$ 759,434	$ 876,757	$ 883,400	$ 935,839	$ 968,958	$ 1,074,572	$ 1,101,937	$ 1,092,407	$ 1,117,403
Mexico Beach	Bay	$ 14,284	$ 14,766	$ 14,888	$ 15,679	$ 16,821	$ 19,948	$ 21,408	$ 17,013	$ 18,343
Panama City	Bay	$ 2,614,508	$ 2,872,976	$ 2,855,178	$ 2,802,057	$ 2,812,818	$ 3,041,802	$ 3,198,731	$ 3,199,654	$ 3,254,038
Panama City Beach	Bay	$ -	$ 1,539,341	$ 1,754,700	$ 1,940,772	$ 2,041,188	$ 2,299,134	$ 2,332,026	$ 2,422,565	$ 2,523,330
Parker	Bay	$ 302,500	$ 330,212	$ 309,270	$ 325,513	$ 315,394	$ 347,789	$ 339,794	$ 327,998	$ 335,559
Springfield	Bay	$ 411,544	$ 443,533	$ 479,979	$ 421,317	$ 394,584	$ 454,303	$ 450,839	$ 430,865	NR
Brooker	Bradford	$ 6,934	$ 7,940	$ 7,814	$ 8,410	$ 8,527	$ 9,815	$ 8,219	$ 8,788	$ 8,881
Hampton	Bradford	$ 19,478	$ 22,212	$ 26,763	$ 14,479	$ 19,429	$ 26,508	$ 22,043	$ 20,150	NR
Lawtey	Bradford	$ 34,198	$ 40,614	$ 43,544	$ -	$ -	$ -	$ 8,167	$ -	$ -
Starke	Bradford	$ 628,777	$ 837,538	$ 601,525	$ 560,748	$ 600,742	$ 566,589	$ 545,329	$ 517,257	$ 628,774
Cape Canaveral	Brevard	$ 654,060	$ 663,166	$ 665,470	$ 663,907	$ 675,207	$ 759,112	$ 734,174	$ 726,005	$ 768,987
Cocoa	Brevard	$ 1,131,989	$ 1,144,990	$ 1,135,200	$ 1,083,088	$ 1,119,970	$ 1,207,944	$ 1,197,383	$ 1,188,420	$ 1,294,321
Cocoa Beach	Brevard	$ 1,116,649	$ 1,117,852	$ 1,093,321	$ 1,026,985	$ 1,072,109	$ 1,167,941	$ 1,144,195	$ 1,123,824	$ 1,206,461
Grant-Valkaria	Brevard	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Indialantic	Brevard	$ 242,376	$ 218,225	$ 223,607	$ 218,697	$ 220,891	$ 246,176	$ 240,487	$ 233,152	$ 250,129
Indian Harbour Beach	Brevard	$ 302,079	$ 307,749	$ 314,653	$ 315,058	$ 317,563	$ 353,378	$ 348,229	$ 351,566	$ 371,323
Malabar	Brevard	$ 192,387	$ 207,273	$ 198,180	$ 199,245	$ 203,045	$ 225,148	$ 221,787	$ 219,299	$ 248,057
Melbourne	Brevard	$ 5,238,322	$ 5,379,795	$ 5,479,476	$ 5,370,027	$ 5,562,352	$ 6,010,459	$ 6,047,410	$ 6,088,803	$ 6,553,097
Melbourne Beach	Brevard	$ 132,085	$ 131,031	$ 129,504	$ 126,853	$ 175,157	$ 206,394	$ 200,390	$ 197,392	$ 206,821
Melbourne Village	Brevard	$ 68,734	$ 70,236	$ 66,567	$ 66,251	$ 50,312	$ 53,014	$ 50,622	$ 49,165	$ 52,909
Palm Bay	Brevard	$ 4,710,289	$ 4,974,545	$ 5,077,132	$ 5,000,445	$ 5,182,844	$ 5,691,766	$ 5,523,218	$ 5,538,018	$ 5,994,198
Palm Shores	Brevard	$ 16,212	$ 17,931	$ 10,416	$ 17,062	$ 18,272	$ 18,181	$ 18,143	$ 18,395	$ 18,739
Rockledge	Brevard	$ 1,492,275	$ 1,538,038	$ 1,530,614	$ 1,536,119	$ 1,563,541	$ 1,703,889	$ 1,678,356	$ 1,686,760	$ 1,825,899
Satellite Beach	Brevard	$ 357,702	$ 360,294	$ 346,318	$ 344,084	$ 350,214	$ 391,748	$ 385,612	$ 375,068	$ 367,177
Titusville	Brevard	$ 2,295,824	$ 2,405,811	$ 2,613,553	$ 2,409,721	$ 2,484,379	$ 2,698,635	$ 2,669,080	$ 2,619,531	$ 2,816,416
West Melbourne	Brevard	$ 973,567	$ 1,038,193	$ 1,034,814	$ 1,079,069	$ 1,162,399	$ 1,329,283	$ 1,351,280	$ 1,425,836	$ 1,573,416
Coconut Creek	Broward	$ 2,533,479	$ 2,535,609	$ 2,621,320	$ 2,689,312	$ 2,689,329	$ 2,939,420	$ 2,915,427	$ 2,990,654	$ 3,202,512
Cooper City	Broward	$ 1,555,619	$ 1,603,056	$ 1,617,872	$ 1,637,183	$ 1,606,768	$ 1,768,837	$ 1,766,902	$ 1,857,074	$ 2,015,714
Coral Springs	Broward	$ 7,129,381	$ 7,279,670	$ 7,228,943	$ 7,226,793	$ 7,135,907	$ 7,690,085	$ 7,589,037	$ 7,731,839	$ 8,138,588
Dania Beach	Broward	$ 2,061,362	$ 2,061,164	$ 2,094,151	$ 2,097,524	$ 2,058,835	$ 2,251,162	$ 2,284,989	$ 2,284,368	$ 2,497,523
Davie	Broward	$ 5,606,601	$ -	$ 6,203,556	$ 6,237,902	$ 6,146,285	$ 6,587,206	$ 6,577,640	$ 6,750,255	$ 7,160,537
Deerfield Beach	Broward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,273,138	$ 5,962,381
Fort Lauderdale	Broward	$ 14,495,903	$ 14,660,098	$ 15,014,546	$ 15,181,470	$ 15,016,127	$ 16,089,695	$ 16,252,773	$ 16,557,010	$ 17,705,388
Hallandale Beach	Broward	$ 2,291,071	$ 2,355,770	$ 2,454,572	$ 2,534,168	$ 2,493,406	$ 2,700,471	$ 2,787,178	$ 2,877,983	$ 3,071,668
Hillsboro Beach	Broward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hollywood	Broward	$ 9,038,361	$ 9,109,196	$ 9,112,528	$ 9,091,160	$ 8,874,121	$ 9,543,254	$ 9,638,728	$ 9,787,753	$ 10,462,144
Lauderdale Lakes	Broward	$ 1,378,016	$ 1,389,752	$ 1,416,847	$ 1,405,424	$ 1,387,601	$ 1,502,365	$ 1,517,648	$ 1,549,135	$ 1,671,308
Lauderdale-By-The-Sea	Broward	$ 539,989	$ 537,575	$ 604,215	$ 657,572	$ 661,306	$ 711,954	$ 710,943	$ 715,447	$ 770,067
Lauderhill	Broward	$ 2,629,595	$ 2,827,823	$ 2,944,746	$ 2,931,648	$ 2,893,752	$ 3,175,869	$ 3,139,183	$ 3,208,185	$ 3,405,435
Lazy Lake	Broward	$ -	$ -	$ -	$ 2,954	$ -	$ -	$ -	$ -	$ -

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Lighthouse Point	Broward	$ 853,362	$ 844,974	$ 863,493	$ 874,983	$ 864,896	$ 946,372	$ 944,078	$ 957,895	$ 1,015,477
Margate	Broward	$ 2,837,929	$ 2,862,747	$ 2,792,989	$ 2,746,230	$ 2,677,740	$ 2,914,470	$ 2,907,772	$ 2,986,147	$ 3,183,483
Miramar	Broward	$ 5,072,998	$ 5,351,779	$ 5,511,786	$ 5,693,534	$ 5,745,841	$ 6,391,527	$ 6,470,570	$ 6,688,747	$ 7,127,144
North Lauderdale	Broward	$ 1,518,796	$ 1,525,339	$ 1,535,645	$ 1,547,654	$ 1,509,085	$ 1,637,310	$ 1,646,739	$ 1,710,427	$ 1,855,295
Oakland Park	Broward	$ 2,190,240	$ 2,490,070	$ 2,576,877	$ 2,578,591	$ 2,486,855	$ 2,676,988	$ 2,677,832	$ 2,716,158	$ 2,908,653
Parkland	Broward	$ 1,209,038	$ 1,281,143	$ 1,365,030	$ 1,472,588	$ 1,462,725	$ 1,644,287	$ 1,629,998	$ 1,659,228	$ 1,774,608
Pembroke Park	Broward	$ 429,163	$ 469,531	$ 496,372	$ 559,027	$ 573,267	$ 595,073	$ 609,209	$ 630,499	$ 670,688
Pembroke Pines	Broward	$ 7,931,137	$ 8,084,904	$ 8,093,581	$ 8,220,015	$ 8,124,202	$ 8,840,661	$ 8,788,592	$ 9,076,627	$ 9,587,367
Plantation	Broward	$ 5,635,479	$ 5,847,452	$ 5,775,640	$ 5,781,447	$ 5,567,049	$ 6,119,327	$ 6,085,785	$ 6,188,100	$ 6,544,219
Pompano Beach	Broward	$ 7,523,375	$ 7,594,269	$ 7,638,627	$ 7,748,947	$ 7,572,270	$ 8,040,324	$ 8,074,816	$ 8,227,734	$ 8,840,851
Sea Ranch Lakes	Broward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Southwest Ranches	Broward	$ 496,246	$ 521,151	$ 580,973	$ 586,114	$ 589,486	$ 652,854	$ 654,966	$ 675,133	$ 712,967
Sunrise	Broward	$ 5,200,422	$ 5,215,841	$ 5,209,406	$ 5,274,627	$ 5,283,127	$ 5,666,076	$ 5,662,601	$ 5,827,061	$ 6,204,168
Tamarac	Broward	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,185,834	$ 3,668,839	$ 3,802,920
West Park	Broward	$ -	$ -	$ 504,164	$ 555,015	$ 535,506	$ 585,131	$ 598,003	$ 611,255	$ 705,898
Weston	Broward	$ 4,010,465	$ 4,121,406	$ 4,120,628	$ 4,198,618	$ 4,158,022	$ 4,515,072	$ 4,427,926	$ 4,445,301	$ 4,707,507
Wilton Manors	Broward	$ 729,751	$ 731,591	$ 753,435	$ 772,129	$ 770,469	$ 861,322	$ 865,469	$ 880,877	$ 943,129
Altha	Calhoun	$ 32,300	$ 33,673	$ 28,840	$ 30,979	$ 31,546	$ 32,614	$ 45,331	$ 36,148	$ 28,760
Blountstown	Calhoun	$ 113,628	$ 128,921	$ 140,379	$ 149,296	$ 179,927	$ 199,470	$ 192,911	$ 179,343	$ 162,969
Punta Gorda	Charlotte	$ 1,111,653	$ 1,083,567	$ 1,093,829	$ 1,112,626	$ 1,163,039	$ 1,308,911	$ 1,281,050	$ 1,252,996	$ 1,358,740
Crystal River	Citrus	$ 405,109	$ 434,937	$ 426,778	$ 439,347	$ 448,570	$ 536,256	$ 516,014	$ 476,570	$ 498,234
Inverness	Citrus	$ 534,456	$ 549,106	$ 551,146	$ 554,037	$ 592,443	$ 680,862	$ 649,084	$ 639,648	$ 684,324
Green Cove Springs	Clay	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Keystone Heights	Clay	$ -	$ -	$ -	$ -	$ 58,029	$ 73,172	$ 93,886	$ 87,510	$ 86,607
Orange Park	Clay	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Penney Farms	Clay	$ -	$ -	$ -	$ -	$ -	$ 30,948	$ 40,470	$ 38,978	$ 43,570
Everglades	Collier	$ 46,362	$ -	$ 44,943	$ 54,437	$ -	$ -	$ -	$ -	$ 92,145
Marco Island	Collier	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Naples	Collier	$ 2,336,099	$ 2,365,308	$ 2,354,298	$ 2,290,253	$ 2,392,073	$ 2,538,471	$ 2,537,330	$ 2,582,461	$ 2,794,311
Fort White	Columbia	$ -	$ 10,738	$ 3,171	$ 2,592	$ 3,818	$ 4,621	$ 6,090	$ 8,257	$ 7,181
Lake City	Columbia	$ 882,931	$ 920,112	$ 925,119	$ 962,516	$ 1,011,129	$ 1,068,131	$ 1,086,614	$ 1,055,645	$ 1,128,848
Arcadia	DeSoto	$ 317,877	$ 328,242	$ 317,658	$ 291,852	$ 296,889	$ 322,958	$ 320,874	$ 313,653	NR
Cross City	Dixie	$ 108,419	$ 115,720	$ 107,061	$ 114,851	$ 118,167	$ 128,020	$ 121,214	$ 106,806	$ 112,031
Horseshoe Beach	Dixie	$ -	$ 16,882	$ 19,922	$ 17,583	$ 17,582	$ 18,017	$ 17,751	$ 18,985	$ 19,096
Atlantic Beach	Duval	$ 367,186	$ 372,226	$ 363,285	$ 392,842	$ 430,774	$ 486,475	$ 487,585	$ 452,184	$ 459,672
Baldwin	Duval	$ 84,351	$ 84,722	$ 79,733	$ 89,011	$ 98,826	$ 106,759	$ 125,786	$ 102,305	$ 104,790
Jacksonville	Duval	$ 46,851,288	$ 48,130,818	$ 47,738,296	$ 56,386,853	$ 61,556,310	$ 69,336,843	$ 71,920,899	$ 67,278,923	$ 68,284,589
Jacksonville Beach	Duval	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Neptune Beach	Duval	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Century	Escambia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pensacola	Escambia	$ 4,091,458	$ 4,572,114	$ 4,512,314	$ 4,414,957	$ 4,554,938	$ 5,039,536	$ 5,099,161	$ 4,916,612	$ 5,015,463
Beverly Beach	Flagler	$ -	$ -	$ -	$ 102,427	$ 27,138	$ 27,122	$ 25,736	$ 22,846	$ -
Bunnell	Flagler	$ 133,795	$ 159,450	$ 151,997	$ 180,010	$ 174,556	$ 192,068	$ 194,426	$ 188,006	$ 204,245
Palm Coast	Flagler	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marineland	Flagler/St. Johns	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Flagler Beach	Flagler/Volusia	$ 312,400	$ 310,481	$ 290,928	$ 287,909	$ 301,825	$ 344,316	$ 336,540	$ 328,254	$ 359,903
Apalachicola	Franklin	$ 87,593	$ 94,233	$ 92,967	$ 90,987	$ 95,789	$ 94,760	$ 94,908	$ 96,129	$ 94,857
Carrabelle	Franklin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chattahoochee	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Greensboro	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gretna	Gadsden	$ -	$ -	$ -	$ -	$ 45,040	$ 73,822	$ 39,299	$ 48,837	NR
Havana	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Midway	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Quincy	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	NR
Bell	Gilchrist	$ 20,619	$ 21,816	$ 22,365	$ 16,579	$ 16,479	$ 16,696	$ 15,330	$ 14,328	$ 13,553
Trenton	Gilchrist	$ 94,088	$ 107,224	$ 106,745	$ 108,247	$ 125,732	$ 134,531	$ 123,559	$ 111,748	$ 119,420
Fanning Springs	Gilchrist/Levy	$ 56,867	$ 64,574	$ 69,070	$ 54,505	$ 54,863	$ 59,255	$ 54,706	$ 50,702	$ 48,658
Moore Haven	Glades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Port St. Joe	Gulf	$ 167,278	$ 185,326	$ 190,456	$ 194,822	$ 200,729	$ 216,098	$ 228,076	$ 201,948	$ 217,343
Wewahitchka	Gulf	$ 117,147	$ 109,800	$ 120,410	$ 168,849	$ 167,361	$ 174,162	$ 170,251	$ 165,259	$ 187,075
Jasper	Hamilton	$ 67,130	$ 70,701	$ 71,514	$ 98,079	$ 69,647	$ 73,990	$ 111,393	$ 101,699	$ 71,572
Jennings	Hamilton	$ 43,144	$ 48,754	$ 42,641	$ 46,243	$ 48,754	$ 56,034	$ 54,294	$ 47,681	$ 48,208
White Springs	Hamilton	$ 27,894	$ 41,646	$ 38,097	$ 38,603	$ 41,036	$ 48,572	$ 45,674	$ 40,084	$ 44,296
Bowling Green	Hardee	$ 81,156	$ 84,995	$ 81,384	$ 97,201	$ 88,654	$ 109,965	$ 112,975	$ 89,593	$ 99,323
Wauchula	Hardee	$ 247,045	$ 263,471	$ 271,600	$ 274,006	$ 280,593	$ 283,360	$ 303,025	$ 227,855	$ 242,342
Zolfo Springs	Hardee	$ 41,438	$ 49,047	$ 44,129	$ 53,298	$ 45,833	$ 53,532	$ 55,568	$ 46,415	$ 51,825
Clewiston	Hendry	$ 571,135	$ 573,864	$ 572,070	$ 574,725	$ 546,593	$ 566,515	$ 549,331	$ 518,705	$ 499,638
LaBelle	Hendry	$ 150,034	$ 157,400	$ 159,685	$ 154,397	$ 156,077	$ 171,043	$ 170,173	$ 167,632	$ 172,992
Brooksville	Hernando	$ 539,151	$ 571,567	$ 564,326	$ 605,699	$ 672,993	$ 783,186	$ 717,829	$ 749,992	$ 705,080
Weeki Wachee	Hernando	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avon Park	Highlands	$ 459,486	$ 491,542	$ 514,077	$ 513,572	$ 545,661	$ 620,399	$ 571,403	$ 547,838	$ 578,857
Lake Placid	Highlands	$ 164,508	$ 178,983	$ 182,892	$ 186,539	$ 187,174	$ 217,411	$ 204,401	$ 195,929	$ 203,980
Sebring	Highlands	$ 756,730	$ 844,442	$ 912,865	$ 846,562	$ 931,699	$ 1,091,650	$ 1,034,196	$ 967,356	$ 1,001,595
Plant City	Hillsborough	$ 2,654,820	$ 2,527,112	$ 2,509,492	$ 2,717,426	$ 2,823,222	$ 3,119,806	$ 3,023,814	$ 2,990,240	$ 3,000,256
Tampa	Hillsborough	$ 26,441,509	$ 25,207,232	$ 24,752,937	$ 26,302,572	$ 28,282,581	$ 32,569,274	$ 30,983,435	$ 30,947,584	$ 30,374,339
Temple Terrace	Hillsborough	$ 1,590,578	$ 1,568,527	$ 1,692,601	$ 1,675,336	$ 1,861,447	$ 2,117,542	$ 1,984,452	$ 1,924,442	$ 1,908,035
Bonifay	Holmes	$ 151,535	$ 166,485	$ 167,742	$ 165,526	$ 166,241	$ 182,209	$ 179,942	$ 172,828	$ 176,177
Esto	Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Noma	Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,183
Ponce de Leon	Holmes	$ 14,643	$ 15,889	$ 17,291	$ -	$ -	$ -	$ -	$ -	$ -
Westville	Holmes	$ -	$ -	$ -	$ -	$ -	$ 5,943	$ 6,590	$ 6,583	$ 5,952
Fellsmere	Indian River	$ 98,643	$ 114,097	$ 111,270	$ 120,544	$ 165,514	$ 181,696	$ 188,236	$ 194,777	$ 222,145
Indian River Shores	Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orchid	Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sebastian	Indian River	$ 1,008,541	$ 1,098,225	$ 1,113,771	$ 1,130,033	$ 1,174,792	$ 1,305,187	$ 1,276,549	$ 1,263,888	$ 1,366,798
Vero Beach	Indian River	$ 1,735,401	$ 1,958,001	$ 1,938,426	$ 1,874,121	$ 1,810,262	$ 1,758,675	$ 1,688,786	$ 1,702,265	$ 1,653,373
Alford	Jackson	$ 18,700	$ -	$ 21,185	$ 20,432	$ 22,091	$ 24,287	$ 21,019	$ 21,220	$ 21,476
Bascom	Jackson	$ 2,260	$ 2,091	$ 1,885	$ 2,383	$ 2,080	$ 2,429	$ 2,429	$ 2,637	$ 1,804
Campbellton	Jackson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cottondale	Jackson	$ 37,136	$ 41,217	$ -	$ 40,454	$ 36,528	$ 42,643	$ 38,814	$ 35,179	$ 35,975
Graceville	Jackson	$ 121,600	$ 136,422	$ 147,368	$ 139,213	$ 133,077	$ 155,458	$ 151,725	$ 145,810	$ 149,338
Grand Ridge	Jackson	$ 36,019	$ -	$ 43,473	$ 46,937	$ 51,373	$ 54,438	$ 53,343	$ 49,227	$ 50,914
Greenwood	Jackson	$ -	$ -	$ -	$ -	$ 44,373	$ 42,958	$ 45,460	$ 36,671	$ 37,215
Jacob City	Jackson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Malone	Jackson	$ 22,734	$ 26,001	$ 22,971	$ 24,547	$ 24,652	$ 27,138	$ 25,285	$ 23,990	$ 24,547
Marianna	Jackson	$ 378,700	$ 381,300	$ 378,400	$ 409,994	$ 468,855	$ 524,394	$ 522,225	$ 492,885	$ 530,330
Sneads	Jackson	$ 86,418	$ 101,969	$ 104,560	$ 107,233	$ 117,740	$ 120,402	$ 113,263	$ 108,407	$ 106,101
Monticello	Jefferson	$ 164,946	$ 188,788	$ 171,159	$ 184,456	$ 194,291	$ 240,703	$ 203,532	$ 179,144	$ 15,082
Mayo	Lafayette	$ 26,036	$ 32,044	$ 30,111	$ 29,849	$ 31,831	$ 37,149	$ 32,921	$ 31,723	$ 33,061
Astatula	Lake	$ 98,051	$ 104,374	$ 108,500	$ 122,104	$ 100,360	$ 115,625	$ 110,856	$ 96,847	NR
Clermont	Lake	$ 1,276,893	$ 1,478,785	$ 1,559,824	$ 1,688,421	$ 1,846,153	$ 2,232,203	$ 2,197,178	$ 2,081,111	$ 2,121,508
Eustis	Lake	$ 1,019,687	$ 1,103,845	$ 1,145,763	$ 1,169,908	$ 1,209,378	$ 1,431,847	$ 1,343,688	$ 1,232,641	$ 1,283,237
Fruitland Park	Lake	$ 194,538	$ 201,301	$ 240,832	$ 254,687	$ 279,826	$ 300,196	$ 300,729	$ 282,571	$ 296,418
Groveland	Lake	$ 229,123	$ 290,033	$ 350,312	$ 379,717	$ 404,586	$ 492,499	$ 479,241	$ 476,216	NR

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Howey-in-the-Hills	Lake	$ 42,733	$ 51,096	$ 64,180	$ 63,047	$ 67,804	$ 80,611	$ 73,947	$ 66,621	$ 68,718
Lady Lake	Lake	$ 614,804	$ 658,276	$ 649,449	$ 677,439	$ 756,640	$ 935,571	$ 874,176	$ 808,249	$ 868,960
Leesburg	Lake	$ 2,955,112	$ 2,269,988	$ 2,858,214	$ 3,058,468	$ 3,126,744	$ 3,214,820	$ 3,182,188	$ 2,551,757	$ 2,634,335
Mascotte	Lake	$ 101,620	$ 104,810	$ 106,964	$ 116,449	$ 118,656	$ 134,398	$ 134,054	$ 125,758	$ 133,066
Minneola	Lake	$ -	$ 306,943	$ 311,194	$ 324,635	$ 350,173	$ 417,886	$ 414,097	$ 394,782	$ 389,944
Montverde	Lake	$ 33,541	$ 41,459	$ 37,907	$ 46,789	$ 37,070	$ 50,606	$ 50,669	$ 46,075	$ 50,259
Mount Dora	Lake	$ 934,187	$ 954,794	$ 982,187	$ 1,002,885	$ 1,164,723	$ 1,253,910	$ 1,248,352	$ 1,162,193	$ 1,168,541
Tavares	Lake	$ 655,577	$ 677,960	$ 714,500	$ 743,373	$ 801,502	$ 931,102	$ 907,017	$ 846,893	$ 892,925
Umatilla	Lake	$ 163,093	$ 179,958	$ 177,144	$ 180,289	$ 193,940	$ -	$ 238,266	$ 221,190	$ 232,606
Bonita Springs	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cape Coral	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fort Myers	Lee	$ 4,160,908	$ 4,357,551	$ 4,478,629	$ 4,431,504	$ 4,537,876	$ 4,870,988	$ 4,887,532	$ 5,030,023	$ 5,534,839
Fort Myers Beach	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 907,282
Sanibel	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tallahassee	Leon	$ 8,177,000	$ 9,108,000	$ 10,092,000	$ 10,303,000	$ 10,482,000	$ 10,968,000	$ 11,042,000	$ 10,634,000	$ 10,856,000
Bronson	Levy	$ -	$ -	$ 25,620	$ 22,924	$ 23,526	$ 23,574	$ 21,340	$ 22,133	$ 23,743
Cedar Key	Levy	$ 77,743	$ 79,346	$ 82,393	$ 67,128	$ 29,468	$ -	$ -	$ -	$ -
Chiefland	Levy	$ 281,435	$ 302,068	$ 351,641	$ 265,076	$ 273,557	$ 281,686	$ 266,340	$ 254,823	$ 248,378
Inglis	Levy	$ 98,108	$ 106,024	$ 113,213	$ 83,719	$ 88,951	$ 88,055	$ 79,603	$ 76,681	$ 78,528
Otter Creek	Levy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Williston	Levy	$ 142,924	$ 149,494	$ 281,576	$ 269,295	$ 262,820	$ 267,323	$ 257,956	$ 252,800	$ 273,561
Yankeetown	Levy	$ 34,914	$ 32,725	$ 37,775	$ 25,905	$ 26,857	$ 26,660	$ 23,900	$ 22,679	$ 22,311
Bristol	Liberty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Greenville	Madison	$ 46,312	$ 63,056	$ 61,172	$ 53,614	$ 61,306	$ 61,610	$ 59,114	$ 54,188	$ 51,794
Lee	Madison	$ 22,500	$ 18,395	$ 19,868	$ 21,210	$ 21,374	$ 25,263	$ 23,165	$ 20,232	$ 21,574
Madison	Madison	$ 183,248	$ 223,201	$ 207,329	$ 230,208	$ 223,372	$ 269,293	$ 244,287	$ 237,935	$ 241,820
Anna Maria	Manatee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bradenton	Manatee	$ 2,965,162	$ 3,180,300	$ 2,987,853	$ 2,875,591	$ 2,910,649	$ 3,115,903	$ 3,129,561	$ 3,106,647	$ 3,342,040
Bradenton Beach	Manatee	$ 142,398	$ 139,896	$ 139,508	$ 159,383	$ 150,607	$ 165,690	$ 168,835	$ 165,776	$ 183,978
Holmes Beach	Manatee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palmetto	Manatee	$ 699,486	$ 720,594	$ 784,268	$ 786,221	$ 809,866	$ 886,900	$ 877,381	$ 874,216	$ 943,661
Longboat Key	Manatee/Sarasota	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Belleview	Marion	$ 121,094	$ 135,987	$ 129,245	$ 138,163	$ 140,075	$ 148,962	$ 146,170	$ 142,327	$ 147,030
Dunnellon	Marion	$ 188,071	$ 203,227	$ 203,636	$ 202,213	$ -	$ 252,176	$ 234,822	$ 211,389	$ 225,961
McIntosh	Marion	$ 30,025	$ 31,564	$ 29,824	$ 30,531	$ 30,708	$ 34,259	$ 36,229	$ 29,909	$ 30,755
Ocala	Marion	$ 6,678,610	$ 6,445,774	$ 7,487,077	$ 8,018,318	$ 7,054,528	$ 9,376,714	$ 7,149,961	$ 7,817,303	$ 8,369,228
Reddick	Marion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jupiter Island	Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ocean Breeze Park	Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sewall's Point	Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Stuart	Martin	$ 1,415,784	$ 1,469,328	$ 1,527,888	$ 1,558,090	$ 1,560,149	$ 1,684,561	$ 1,734,911	$ 1,759,615	$ 1,857,777
Aventura	Miami-Dade	$ 3,232,737	$ 3,319,819	$ 3,363,499	$ 3,635,065	$ 3,706,940	$ 3,885,934	$ 3,923,703	$ 3,990,392	$ 4,259,017
Bal Harbour	Miami-Dade	$ 544,934	$ 551,774	$ 557,873	$ 578,391	$ 600,266	$ 630,356	$ 680,284	$ 762,411	$ 808,758
Bay Harbor Islands	Miami-Dade	$ 331,714	$ 336,370	$ 326,219	$ 340,978	$ 332,240	$ 366,402	$ 369,845	$ 379,088	$ 402,225
Biscayne Park	Miami-Dade	$ 108,302	$ 103,535	$ 106,122	$ -	$ 98,841	$ -	$ 111,836	$ 111,510	$ 122,709
Coral Gables	Miami-Dade	$ 4,804,329	$ 4,875,856	$ 4,966,909	$ 5,024,381	$ 5,001,967	$ 5,351,951	$ 5,365,817	$ 5,487,578	$ 5,862,360
Cutler Bay	Miami-Dade	$ -	$ 1,089,066	$ 1,615,484	$ 1,931,744	$ 1,948,917	$ 2,136,783	$ 2,155,194	$ 2,225,104	$ 2,386,783
Doral	Miami-Dade	$ 2,328,733	$ 1,912,727	$ 3,685,954	$ 5,400,763	$ 5,514,694	$ 5,771,287	$ 5,852,712	$ 6,033,261	$ 6,492,296
El Portal	Miami-Dade	$ 61,951	$ 62,896	$ 64,919	$ 66,280	$ 60,786	$ 71,448	$ 71,081	$ 69,484	$ 72,481
Florida City	Miami-Dade	$ 444,280	$ 455,251	$ 461,630	$ 539,598	$ 554,273	$ 583,757	$ 596,604	$ 634,779	$ 686,294
Golden Beach	Miami-Dade	$ -	$ -	$ 92,140	$ 95,675	$ 95,877	$ 104,107	$ -	$ -	$ -
Hialeah	Miami-Dade	$ 9,782,673	$ 9,998,996	$ 10,115,832	$ 10,246,819	$ 9,949,659	$ 10,654,776	$ 10,993,230	$ 11,491,228	$ 14,330,394

Summary of Reported Municipal Public Service Tax - Electricity Revenues
Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Hialeah Gardens	Miami-Dade	$ 780,285	$ 802,826	$ 865,043	$ 969,996	$ 979,409	$ 1,022,858	$ 1,008,600	$ 1,056,283	$ 1,128,129
Homestead	Miami-Dade	$ 1,085,451	$ 1,169,141	$ 1,221,947	$ 1,210,830	$ 1,165,048	$ 1,216,444	$ 1,165,934	$ 1,199,919	$ 1,186,812
Indian Creek	Miami-Dade	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Key Biscayne	Miami-Dade	$ 1,160,977	$ 1,151,314	$ 1,119,692	$ -	$ 1,159,583	$ 1,247,644	$ 1,253,484	$ 1,290,428	$ 1,371,430
Medley	Miami-Dade	$ 936,375	$ 1,035,414	$ 1,044,191	$ 1,034,095	$ 993,101	$ 964,572	$ 999,631	$ 1,001,455	$ 1,089,621
Miami	Miami-Dade	$ -	$ -	$ 21,585,108	$ 22,277,609	$ 22,599,760	$ 25,047,038	$ 26,195,243	$ 27,573,832	$ 29,639,931
Miami Beach	Miami-Dade	$ 7,582,795	$ 7,704,683	$ 7,718,812	$ 7,930,859	$ 8,124,934	$ 8,870,443	$ 9,002,020	$ 9,228,623	$ 10,138,226
Miami Gardens	Miami-Dade	$ 2,818,967	$ 3,753,741	$ 4,735,403	$ 5,032,682	$ 5,267,259	$ 5,473,141	$ 5,458,988	$ 5,578,789	$ 5,915,587
Miami Lakes	Miami-Dade	$ 2,053,024	$ 2,180,288	$ 2,119,404	$ 2,235,430	$ 2,255,833	$ 2,403,604	$ 2,450,483	$ 2,502,818	$ 2,668,536
Miami Shores	Miami-Dade	$ 648,460	$ 659,812	$ 660,762	$ -	$ 663,258	$ 727,475	$ 737,523	$ 732,334	$ 793,025
Miami Springs	Miami-Dade	$ 892,535	$ 928,122	$ 937,710	$ 908,160	$ 776,029	$ 833,756	$ 812,000	$ 834,568	$ 893,573
North Bay	Miami-Dade	$ 301,701	$ 352,874	$ 328,621	$ 388,386	$ 391,473	$ 416,635	$ 416,635	$ 458,847	$ 494,010
North Miami	Miami-Dade	$ 2,319,486	$ 2,435,688	$ 2,433,234	$ 2,357,681	$ 2,335,833	$ 2,552,041	$ 2,595,995	$ 2,695,856	$ 2,894,331
North Miami Beach	Miami-Dade	$ 1,818,397	$ 1,916,695	$ 1,878,990	$ 1,940,915	$ 1,904,427	$ 2,102,783	$ 2,139,800	$ 2,175,878	$ 2,317,294
Opa-locka	Miami-Dade	$ 795,131	$ 825,201	$ 857,384	$ 851,004	$ 710,579	$ 832,380	$ 1,050,358	$ 811,650	$ 996,993
Palmetto Bay	Miami-Dade	$ 1,483,259	$ 1,468,227	$ 1,521,330	$ 1,678,953	$ 1,662,906	$ 1,811,204	$ 1,795,763	$ 1,833,218	$ 1,931,352
Pinecrest	Miami-Dade	$ 1,565,423	$ 1,567,345	$ 1,566,173	$ 1,622,205	$ 1,601,485	$ -	$ 1,714,422	$ 1,751,187	$ 1,845,433
South Miami	Miami-Dade	$ 873,360	$ 931,008	$ 954,566	$ 1,022,767	$ 1,034,327	$ 1,111,694	$ 1,136,433	$ 1,166,162	$ 1,276,842
Sunny Isles Beach	Miami-Dade	$ 1,287,797	$ 1,418,335	$ 1,512,932	$ 1,721,280	$ 1,864,430	$ 2,062,927	$ 2,107,901	$ 2,146,637	$ 2,322,488
Surfside	Miami-Dade	$ 407,360	$ 422,478	$ 422,132	$ 415,994	$ 403,591	$ 439,018	$ 447,280	$ 452,591	$ 477,566
Sweetwater	Miami-Dade	$ 476,702	$ 480,132	$ 482,868	$ 492,734	$ 478,309	$ -	$ 524,283	$ 557,808	$ 585,314
Virginia Gardens	Miami-Dade	$ 163,434	$ 186,321	$ 185,969	$ 189,223	$ 188,426	$ 201,654	$ 200,723	$ 207,230	$ 217,074
West Miami	Miami-Dade	$ 237,381	$ 236,138	$ 263,911	$ 272,024	$ 278,661	$ 303,300	$ 307,160	$ 316,256	$ 328,448
Islamorada	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Key Colony Beach	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Key West	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Layton	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marathon	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Callahan	Nassau	$ 10,311	$ 23,718	$ 11,115	$ 8,797	$ 7,837	$ 5,332	$ 7,370	$ 9,583	$ 9,117
Fernandina Beach	Nassau	$ 467,228	$ 477,774	$ -	$ -	$ -	$ -	$ 625,754	$ 617,285	$ 609,002
Hilliard	Nassau	$ 50,721	$ 59,580	$ 60,276	$ 61,847	$ 73,285	$ 67,683	$ 64,899	$ 61,843	$ 64,064
Cinco Bayou	Okaloosa	$ 28,725	$ 30,662	$ 30,197	$ 29,226	$ 29,372	$ 31,245	$ 31,148	$ 31,321	$ 32,156
Crestview	Okaloosa	$ 1,004,919	$ 1,161,740	$ 822,944	$ 1,199,066	$ 1,234,725	$ 1,466,245	$ 1,517,629	$ 1,542,798	$ 1,578,230
Destin	Okaloosa	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fort Walton Beach	Okaloosa	$ 1,191,418	$ 1,302,539	$ 1,291,185	$ 1,280,128	$ 1,592,831	$ 1,804,128	$ 1,845,820	$ 1,813,348	$ 1,813,966
Laurel Hill	Okaloosa	$ 14,082	$ 16,937	$ 19,034	$ 19,536	$ 22,845	$ 21,243	$ 38,908	$ 21,201	$ 21,815
Mary Esther	Okaloosa	$ 197,702	$ 203,391	$ 203,991	$ -	$ -	$ 197,664	$ 197,576	$ 198,755	$ 202,147
Niceville	Okaloosa	$ 731,877	$ 794,054	$ 796,529	$ 789,214	$ 797,613	$ 915,814	$ 937,145	$ 938,359	$ 958,499
Shalimar	Okaloosa	$ 46,291	$ 52,105	$ 53,006	$ 46,437	$ 49,729	$ 51,978	$ 52,656	$ 54,143	$ 55,078
Valparaiso	Okaloosa	$ 161,521	$ 166,694	$ 171,219	$ 167,460	$ 166,932	$ 174,570	$ 174,679	$ 177,601	$ 182,449
Okeechobee	Okeechobee	$ 319,444	$ 361,568	$ 427,430	$ 402,052	$ 406,558	$ 436,918	$ 425,421	$ 411,944	$ 436,682
Apopka	Orange	$ 1,632,856	$ 1,889,669	$ 1,943,196	$ 2,078,581	$ 2,079,707	$ 2,485,810	$ 2,416,441	$ 2,152,353	$ 2,396,409
Bay Lake	Orange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Belle Isle	Orange	$ 110,819	$ 115,206	$ 111,052	$ 122,368	$ 121,832	$ 148,837	$ -	$ 137,968	$ 140,572
Eatonville	Orange	$ 207,192	$ 253,576	$ 281,705	$ -	$ 347,626	$ 398,184	$ 382,144	$ 368,132	$ 396,032
Edgewood	Orange	$ 219,905	$ 426,198	$ 284,103	$ 292,223	$ 311,612	$ 345,239	$ 332,976	$ 318,966	$ 326,053
Lake Buena Vista	Orange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maitland	Orange	$ 1,739,806	$ 1,904,457	$ 1,957,775	$ 1,940,598	$ 2,023,271	$ 2,378,189	$ 2,245,265	$ 2,085,118	$ 2,195,119
Oakland	Orange	$ 110,881	$ -	$ 130,846	$ 129,264	$ 134,331	$ 172,536	$ 147,810	$ 135,665	$ 146,156
Ocoee	Orange	$ 1,889,206	$ 2,135,535	$ 2,204,475	$ 2,268,895	$ 2,306,021	$ 2,670,345	$ 2,553,667	$ 2,364,736	$ 2,454,414
Orlando	Orange	$ 21,564,188	$ 22,446,087	$ 24,648,623	$ 25,576,240	$ 27,877,075	$ 30,130,307	$ 29,816,881	$ 28,858,045	$ 27,675,532
Windermere	Orange	$ 189,435	$ 210,667	$ 217,471	$ 225,128	$ 243,060	$ 291,280	$ 280,958	$ 259,930	$ 206,336

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Winter Garden	Orange	$ 1,457,544	$ 1,739,803	$ 1,976,047	$ 2,156,980	$ 2,253,662	$ 2,803,332	$ 2,640,377	$ 2,419,663	$ 2,550,293
Winter Park	Orange	$ 2,625,437	$ 2,903,648	$ 2,963,353	$ 3,002,455	$ 3,114,873	$ 3,695,914	$ 3,525,012	$ 3,338,652	$ 3,360,006
Kissimmee	Osceola	$ 5,795,000	$ 2,937,000	$ 2,913,379	$ 3,133,000	$ 3,170,000	$ 3,207,000	$ 2,744,000	$ 3,415,000	$ 3,560
St. Cloud	Osceola	$ 1,133,352	$ 1,286,095	$ 1,489,295	$ 1,555,378	$ 1,710,981	$ 1,886,169	$ 1,868,378	$ 1,735,517	$ 1,617,406
Atlantis	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Belle Glade	Palm Beach	$ 638,315	$ 635,518	$ 670,384	$ 695,634	$ 728,362	$ 778,405	$ 769,386	$ 765,648	$ 824,401
Boca Raton	Palm Beach	$ 9,332,787	$ 9,524,013	$ 9,750,757	$ 9,798,646	$ 11,445,225	$ 11,983,938	$ 11,844,844	$ 10,773,576	$ 11,446,261
Boynton Beach	Palm Beach	$ 4,057,187	$ 4,354,332	$ 4,264,467	$ 4,348,159	$ 4,318,365	$ 4,694,042	$ 4,680,999	$ 4,744,498	$ 5,178,324
Briny Breeze	Palm Beach	$ 10,773	$ 10,721	$ 10,296	$ 10,752	$ 9,814	$ 11,146	$ 11,567	$ 11,630	$ 11,992
Cloud Lake	Palm Beach	$ 4,229	$ 4,290	$ 4,381	$ 4,159	$ 3,898	$ 4,625	$ 4,526	$ 4,215	$ 4,389
Delray Beach	Palm Beach	$ 4,008,310	$ 4,198,555	$ 4,164,263	$ 4,152,517	$ 4,365,129	$ 4,840,836	$ 4,836,012	$ 4,930,270	$ 5,202,278
Glen Ridge	Palm Beach	$ 12,524	$ 13,281	$ 13,088	$ 14,050	$ 14,533	$ 16,538	$ 15,835	$ 16,167	$ 17,860
Golf	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Greenacres	Palm Beach	$ 1,491,468	$ 1,668,713	$ 1,635,216	$ 1,625,841	$ 1,631,646	$ 1,780,946	$ 1,785,411	$ 1,808,707	$ 1,930,995
Gulf Stream	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ 66,319	$ 137,235	$ 148,267	$ 165,753
Haverhill	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Highland Beach	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ 438,391	$ 424,682	$ -	$ -
Hypoluxo	Palm Beach	$ 105,846	$ 24,761	$ 104,195	$ 105,765	$ 106,174	$ 117,726	$ 115,461	$ 116,503	$ 125,371
Juno Beach	Palm Beach	$ 241,854	$ 242,255	$ 233,552	$ 230,008	$ 237,717	$ 294,178	$ 330,249	$ 331,178	$ 356,089
Jupiter	Palm Beach	$ 2,253,331	$ 2,406,940	$ 2,327,850	$ 2,380,624	$ 2,461,411	$ 2,688,946	$ 2,684,899	$ 2,754,579	$ 2,959,183
Jupiter Inlet Colony	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lake Clarke Shores	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lake Park	Palm Beach	$ 547,350	$ 560,625	$ 549,648	$ 563,614	$ 556,670	$ 607,096	$ 613,238	$ 621,259	$ 667,672
Lake Worth	Palm Beach	$ 2,250,201	$ 3,460,604	$ 2,379,179	$ 2,421,195	$ 2,270,891	$ 2,453,258	$ 2,637,397	$ 2,072,100	$ 1,896,128
Lantana	Palm Beach	$ 623,664	$ 649,352	$ 666,655	$ 682,295	$ 651,189	$ 711,388	$ 700,642	$ 704,225	$ 751,631
Loxahatchee Groves	Palm Beach	$ -	$ -	$ -	$ 114,600	$ 196,004	$ 209,777	$ 203,523	$ 203,118	$ 225,396
Manalapan	Palm Beach	$ 149,545	$ 164,713	$ 132,097	$ 129,082	$ 167,919	$ 182,001	$ 184,807	$ 186,585	$ 194,565
Mangonia Park	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ 130,490	$ 128,717	$ 129,988	$ 144,340
North Palm Beach	Palm Beach	$ 914,354	$ 934,599	$ 938,550	$ 942,223	$ 934,198	$ 1,034,593	$ 1,017,774	$ 1,030,127	$ 1,091,884
Ocean Ridge	Palm Beach	$ 158,203	$ 164,998	$ 129,698	$ 148,498	$ 178,664	$ 206,888	$ 204,158	$ 205,909	$ 216,909
Pahokee	Palm Beach	$ 227,296	$ 218,783	$ 217,295	$ 214,140	$ 208,020	$ 229,144	$ 226,651	$ 222,199	$ 223,466
Palm Beach	Palm Beach	$ 1,976,980	$ 2,035,294	$ 2,039,667	$ 2,060,247	$ 2,049,223	$ 2,187,115	$ 2,172,820	$ 2,221,874	$ 2,362,068
Palm Beach Gardens	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palm Beach Shores	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palm Springs	Palm Beach	$ 763,784	$ 847,560	$ 873,368	$ 909,438	$ 930,056	$ 995,546	$ 1,049,360	$ 1,093,550	$ 1,428,048
Riviera Beach	Palm Beach	$ 1,874,850	$ 2,155,168	$ 2,240,764	$ -	$ 2,471,640	$ 2,397,755	$ 2,397,373	$ 2,522,841	$ 2,801,998
Royal Palm Beach	Palm Beach	$ 1,749,565	$ 1,791,930	$ 1,899,349	$ 1,954,826	$ 1,996,922	$ 2,167,701	$ 2,147,928	$ 2,160,221	$ 2,340,259
South Bay	Palm Beach	$ 163,515	$ -	$ 178,672	$ 181,669	$ 180,641	$ 210,579	$ 189,758	$ 190,314	$ 204,378
South Palm Beach	Palm Beach	$ 112,183	$ 110,044	$ 106,896	$ 107,405	$ 99,416	$ 88,560	$ 114,819	$ 115,587	$ 122,718
Tequesta	Palm Beach	$ -	$ 363,620	$ 392,158	$ 397,931	$ 400,266	$ 444,370	$ 434,553	$ 431,414	$ 467,498
Wellington	Palm Beach	$ 3,075,162	$ 3,236,136	$ 3,249,554	$ 3,253,102	$ 3,277,599	$ 3,612,989	$ 3,700,672	$ 3,644,412	$ 3,938,138
West Palm Beach	Palm Beach	$ 7,854,526	$ 8,169,153	$ 7,823,657	$ 7,772,802	$ 7,656,138	$ 8,289,796	$ 8,304,419	$ 8,350,046	$ 9,126,197
Dade City	Pasco	$ 420,757	$ 411,169	$ 425,078	$ 444,235	$ 478,534	$ 572,324	$ 540,774	$ 518,642	$ 519,209
New Port Richey	Pasco	$ 1,086,979	$ 1,178,701	$ 1,188,282	$ 1,162,320	$ 1,219,099	$ 1,432,186	$ 1,327,867	$ 1,210,723	$ 1,277,872
Port Richey	Pasco	$ 286,942	$ 316,501	$ 317,975	$ 312,095	$ 30,721	$ -	$ 220,625	$ 318,735	$ 290,219
San Antonio	Pasco	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Leo	Pasco	$ -	$ -	$ 15,840	$ 31,703	$ 34,595	$ 39,942	$ 42,111	$ 39,656	$ 41,458
Zephyrhills	Pasco	$ 1,064,236	$ 1,186,068	$ 1,244,668	$ 1,248,153	$ 1,335,641	$ 1,515,999	$ 1,435,857	$ 1,369,763	$ 1,477,083
Belleair	Pinellas	$ 320,261	$ 348,180	$ 34,699	$ 379,017	$ 415,012	$ 414,623	$ 380,691	$ 352,172	$ 224,919
Belleair Beach	Pinellas	$ 141,129	$ 152,877	$ 150,824	$ 153,067	$ 161,699	$ 193,984	$ 181,570	$ 164,216	$ 175,551
Belleair Bluffs	Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Belleair Shore	Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Clearwater	Pinellas	$ 8,085,037	$ 8,510,566	$ 8,592,224	$ 8,679,857	$ 9,091,973	$ 10,550,107	$ 9,946,131	$ 9,357,956	$ 9,928,059
Dunedin	Pinellas	$ 2,326,067	$ 2,517,186	$ 2,497,573	$ 2,481,842	$ 2,628,213	$ 3,069,542	$ 2,822,718	$ 2,611,204	$ 2,722,845
Gulfport	Pinellas	$ 694,986	$ 743,774	$ 722,653	$ 747,417	$ 767,047	$ 913,198	$ 861,760	$ 795,054	$ 823,812
Indian Rocks Beach	Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Indian Shores	Pinellas	$ 168,831	$ 225,150	$ 224,442	$ 238,869	$ 258,636	$ 290,804	$ 280,536	$ 262,154	$ 272,674
Kenneth City	Pinellas	$ 137,368	$ 146,768	$ 138,546	$ 141,724	$ 148,609	$ 174,954	$ 168,417	$ 153,057	$ 248,025
Largo	Pinellas	$ 5,150,410	$ 5,589,000	$ 5,621,352	$ 5,736,472	$ 5,879,690	$ 6,859,799	$ 6,427,489	$ 5,894,160	$ 6,397,953
Madeira Beach	Pinellas	$ 437,112	$ 461,441	$ 475,015	$ 482,408	$ 512,353	$ 603,339	$ 564,244	$ 532,148	$ 563,875
North Redington Beach	Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oldsmar	Pinellas	$ 1,116,292	$ 1,069,993	$ 1,057,154	$ 1,111,598	$ 1,235,954	$ 1,384,771	$ 1,346,463	$ 1,307,348	$ 1,302,837
Pinellas Park	Pinellas	$ 3,865,478	$ 4,221,078	$ 4,260,449	$ 4,309,435	$ 4,427,434	$ 5,106,163	$ 4,820,268	$ 4,625,865	$ 4,916,890
Redington Beach	Pinellas	$ 78,440	$ 86,777	$ 84,847	$ 87,779	$ 94,571	$ 110,724	$ 103,931	$ 93,044	$ 100,119
Redington Shores	Pinellas	$ -	$ -	$ -	$ -	$ 203,496	$ 227,018	$ 209,225	$ 202,016	$ 197,277
Safety Harbor	Pinellas	$ 1,103,040	$ 1,220,986	$ 1,214,617	$ 1,241,042	$ 1,294,615	$ 1,501,797	$ 1,377,150	$ 1,304,600	$ 1,365,466
Seminole	Pinellas	$ 869,111	$ 941,243	$ 954,512	$ 969,311	$ 1,003,105	$ 1,137,362	$ 1,065,545	$ 999,293	$ 1,048,407
South Pasadena	Pinellas	$ 417,635	$ 438,324	$ 434,617	$ 437,759	$ 445,197	$ 513,981	$ 496,286	$ 466,924	$ 491,733
St. Pete Beach	Pinellas	$ 1,011,245	$ 1,077,984	$ 1,080,315	$ 1,094,847	$ 1,135,150	$ 1,336,815	$ 1,256,642	$ 1,181,426	$ 1,242,465
St. Petersburg	Pinellas	$ 16,989,020	$ 18,032,091	$ 18,064,761	$ 18,375,628	$ 19,250,219	$ 22,432,711	$ 21,112,967	$ 19,768,164	$ 21,044,031
Tarpon Springs	Pinellas	$ 1,579,595	$ 1,676,592	$ 1,717,458	$ 1,750,533	$ 1,800,168	$ 2,111,156	$ 1,962,501	$ 1,784,494	$ 1,939,631
Treasure Island	Pinellas	$ 396,565	$ 395,446	$ 398,900	$ 407,062	$ 670,145	$ 846,007	$ 806,956	$ 753,605	$ 795,139
Auburndale	Polk	$ 969,414	$ 956,854	$ 1,177,104	$ 1,259,398	$ 1,362,909	$ 1,652,178	$ 1,592,150	$ 1,587,642	$ 1,607,926
Bartow	Polk	$ 1,173,774	$ 1,261,735	$ 1,338,392	$ 1,299,835	$ 1,472,703	$ 1,540,203	$ 1,537,319	$ 1,437,468	$ 1,485,941
Davenport	Polk	$ 151,849	$ 164,940	$ 179,184	$ 219,533	$ 243,551	$ 286,542	$ 269,453	$ 262,358	$ 281,342
Dundee	Polk	$ 173,647	$ 192,080	$ 199,504	$ 213,037	$ 213,608	$ 245,980	$ 230,552	$ 232,027	$ 221,198
Eagle Lake	Polk	$ 79,203	$ 80,169	$ 86,418	$ 89,770	$ 104,031	$ 122,402	$ 118,104	$ 110,795	$ 111,762
Fort Meade	Polk	$ 320,473	$ 384,950	$ 478,404	$ 500,316	$ 585,345	$ 615,094	$ 379,857	$ 399,963	$ 409,810
Frostproof	Polk	$ 206,006	$ 223,603	$ 221,864	$ 207,563	$ 253,361	$ 296,640	$ 249,053	$ 227,516	$ 243,190
Haines City	Polk	$ 790,928	$ 914,378	$ 986,922	$ 1,013,034	$ 1,063,635	$ 1,230,949	$ 1,164,631	$ 1,092,348	$ 1,165,788
Highland Park	Polk	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hillcrest Heights	Polk	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lake Alfred	Polk	$ 238,463	$ 230,261	$ 236,314	$ 255,580	$ 279,075	$ 324,124	$ 304,900	$ 290,107	$ 295,925
Lake Hamilton	Polk	$ 100,118	$ -	$ 131,967	$ 103,720	$ 121,693	$ 103,094	$ 128,371	$ 102,028	$ 108,705
Lake Wales	Polk	$ 942,474	$ 1,056,770	$ 1,112,497	$ 1,131,535	$ 1,174,440	$ 1,345,444	$ 1,292,313	$ 1,199,440	$ 1,252,229
Lakeland	Polk	$ 6,341,371	$ 6,598,518	$ 7,004,201	$ 7,324,452	$ 7,313,240	$ 7,706,494	$ 7,695,514	$ 7,323,308	$ 7,392,707
Mulberry	Polk	$ -	$ -	$ -	$ -	$ -	$ 418,899	$ 380,505	$ 349,281	$ 340,977
Polk City	Polk	$ 79,384	$ 78,491	$ 69,600	$ 86,608	$ 86,316	$ 95,148	$ 86,852	$ 79,089	$ 76,380
Winter Haven	Polk	$ 2,317,657	$ 2,334,745	$ 2,367,826	$ 2,594,261	$ 2,802,430	$ 3,225,015	$ 3,024,470	$ 3,014,888	$ 3,077,286
Crescent City	Putnam	$ 54,790	$ 57,141	$ 55,685	$ 58,611	$ 98,359	$ 107,556	$ 107,771	$ 105,176	$ 112,737
Interlachen	Putnam	$ 55,304	$ 74,349	$ 73,618	$ 78,047	$ 82,626	$ 88,699	$ 83,462	$ 76,698	$ 82,286
Palatka	Putnam	$ 583,829	$ 633,747	$ 605,456	$ 1,504,085	$ 1,525,570	$ 1,533,060	$ 668,075	$ 639,950	$ 651,854
Pomona Park	Putnam	$ 11,524	$ 11,508	$ 11,706	$ 11,650	$ 11,518	$ 11,184	$ 11,726	$ 11,423	$ 11,268
Welaka	Putnam	$ 10,058	$ 10,381	$ 13,840	$ 58,600	$ 58,170	$ 57,544	$ 57,179	$ 14,125	$ 14,580
Gulf Breeze	Santa Rosa	$ -	$ -	$ 108,301	$ 88,179	$ 159,356	$ 245,884	$ 265,847	$ 277,043	$ 275,240
Jay	Santa Rosa	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Milton	Santa Rosa	$ -	$ 458,736	$ 470,455	$ 479,821	$ 486,737	$ 531,778	$ 585,741	$ 549,540	$ 554,710
North Port	Sarasota	$ 379,517	$ 435,921	$ 486,787	$ 510,880	$ 527,522	$ 580,486	$ 584,193	$ 589,511	$ 644,998
Sarasota	Sarasota	$ 4,263,406	$ 4,390,993	$ 4,309,733	$ 4,160,104	$ 4,207,847	$ 4,536,335	$ 4,575,547	$ 4,571,626	$ 4,927,990
Venice	Sarasota	$ 1,610,115	$ 1,702,806	$ 1,710,323	$ 1,711,690	$ 3,680,077	$ 1,910,683	$ 1,750,415	$ 1,915,864	$ 2,102,365
Altamonte Springs	Seminole	$ 2,715,763	$ 2,918,929	$ 2,957,002	$ 2,979,532	$ 3,071,673	$ 3,489,898	$ 3,289,114	$ 3,123,061	$ 3,299,787
Casselberry	Seminole	$ 1,581,327	$ 1,696,050	$ 1,692,191	$ 1,728,419	$ 1,724,396	$ 2,080,495	$ 1,929,886	$ 1,742,412	$ 1,855,485
Lake Mary	Seminole	$ 1,401,325	$ 1,555,394	$ 1,595,986	$ 1,599,976	$ 1,828,275	$ 2,036,420	$ 1,956,131	$ 1,850,581	$ 1,936,906
Longwood	Seminole	$ 1,036,538	$ 1,142,783	$ 1,155,913	$ 1,147,701	$ 1,159,863	$ 1,299,810	$ 1,240,610	$ 1,142,495	$ 1,133,005

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Oviedo	Seminole	$ 1,702,101	$ 2,020,147	$ 2,072,853	$ 2,115,330	$ 2,223,291	$ 2,557,794	$ 2,382,520	$ 2,232,423	$ 2,378,906
Sanford	Seminole	$ 2,883,985	$ 3,135,929	$ 3,158,229	$ 3,200,167	$ 3,324,399	$ 3,576,967	$ 3,573,523	$ 3,531,396	$ 3,830,088
Winter Springs	Seminole	$ 1,711,162	$ 1,955,524	$ 1,916,949	$ 1,963,770	$ 1,919,916	$ 2,469,621	$ 2,196,504	$ 2,015,839	$ 1,951,447
Hastings	St. Johns	$ 104,714	$ 108,484	$ 118,242	$ 86,834	$ 29,884	$ 31,299	$ 32,963	$ 30,884	$ 33,497
St. Augustine	St. Johns	$ 643,310	$ 596,575	$ 711,370	$ 636,611	$ 643,040	$ 894,452	$ 980,395	$ 939,844	$ 1,029,195
St. Augustine Beach	St. Johns	$ 412,104	$ 425,673	$ 428,851	$ 424,021	$ 442,003	$ 497,780	$ 495,779	$ 484,811	$ 521,284
Fort Pierce	St. Lucie	$ 2,068,235	$ 1,949,793	$ 1,962,122	$ 2,238,087	$ 2,277,921	$ 2,429,431	$ 2,418,688	$ 2,332,780	$ 2,287,055
Port St. Lucie	St. Lucie	$ 3,180,531	$ 3,548,158	$ 3,799,014	$ 3,937,495	$ 4,010,779	$ 4,517,810	$ 8,634,159	$ 9,075,684	$ -
St. Lucie Village	St. Lucie	$ -	$ -	$ -	$ 59,880	$ 75,485	$ 69,878	$ 59,855	$ 54,558	$ 51,989
Bushnell	Sumter	$ 119,901	$ 144,690	$ 117,188	$ 123,975	$ 146,641	$ 157,348	$ 152,190	$ 134,292	$ 154,322
Center Hill	Sumter	$ 35,765	$ 37,490	$ 36,906	$ 37,678	$ 40,701	$ 51,873	$ 48,209	$ 44,113	$ 51,789
Coleman	Sumter	$ 33,171	$ 36,089	$ 35,376	$ 34,988	$ 38,067	$ 43,949	$ 41,771	$ 36,984	$ 38,117
Webster	Sumter	$ 33,928	$ -	$ 35,814	$ 33,080	$ 35,528	$ 44,013	$ 42,830	$ 42,687	NR
Wildwood	Sumter	$ 194,528	$ 226,217	$ 255,646	$ 274,173	$ 195,069	$ 182,460	$ 244,366	$ 310,577	$ 462,968
Branford	Suwannee	$ -	$ 52,588	$ 54,231	$ 53,511	$ 56,130	$ 66,515	$ 64,739	$ -	$ 68,668
Live Oak	Suwannee	$ 439,788	$ 519,318	$ 517,428	$ 528,944	$ 528,741	$ 527,019	$ 542,308	$ 522,393	$ 548,744
Perry	Taylor	$ 471,160	$ 497,151	$ 518,020	$ 473,336	$ 572,683	$ 663,647	$ 674,045	$ 481,003	$ 579,497
Lake Butler	Union	$ 25,514	$ 27,131	$ 26,687	$ 166,591	$ 27,867	$ 34,003	$ 31,541	$ 28,925	$ 31,424
Raiford	Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Worthington Springs	Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Daytona Beach	Volusia	$ 4,943,108	$ 5,053,145	$ 4,921,414	$ 4,866,065	$ 5,020,783	$ 5,422,020	$ 5,387,030	$ 5,293,930	$ 5,763,949
Daytona Beach Shores	Volusia	$ 353,000	$ 357,000	$ 371,137	$ 370,670	$ 383,554	$ 413,000	$ 410,000	$ 406,000	$ 426,000
DeBary	Volusia	$ 810,345	$ 1,027,356	$ 1,078,074	$ 1,115,172	$ 1,192,703	$ 1,405,249	$ 1,313,872	$ 1,173,050	$ 1,250,617
DeLand	Volusia	$ 1,861,145	$ 2,156,565	$ 2,242,273	$ 2,275,857	$ 2,388,677	$ 2,792,406	$ 2,607,528	$ 2,439,565	$ 2,601,981
Deltona	Volusia	$ 3,564,184	$ 3,846,663	$ 3,870,079	$ 3,799,154	$ 4,070,999	$ 4,556,219	$ 4,324,002	$ 4,032,863	$ 4,303,350
Edgewater	Volusia	$ 939,175	$ 1,008,726	$ 1,040,642	$ 887,308	$ 1,010,319	$ 1,113,484	$ 1,076,748	$ 1,055,571	$ 1,148,158
Holly Hill	Volusia	$ 757,813	$ 785,546	$ 780,932	$ 793,872	$ 797,913	$ 856,356	$ 847,841	$ 835,424	$ 903,270
Lake Helen	Volusia	$ 125,774	$ 139,334	$ 141,122	$ 139,150	$ 151,238	$ 179,122	$ 168,684	$ 152,428	$ 165,151
New Smyrna Beach	Volusia	$ 1,555,858	$ 1,610,382	$ -	$ 1,648,500	$ 1,705,662	$ 1,843,561	$ 1,710,658	$ 1,661,109	$ 1,639,550
Oak Hill	Volusia	$ 54,113	$ 57,829	$ 59,167	$ 58,420	$ 59,310	$ 64,873	$ 66,165	$ 64,431	$ 72,164
Orange City	Volusia	$ 616,603	$ 689,801	$ 720,360	$ 759,816	$ 821,553	$ 949,406	$ 927,054	$ 888,770	$ 943,623
Ormond Beach	Volusia	$ 2,882,000	$ 2,989,000	$ 2,908,000	$ 2,865,000	$ 2,942,000	$ 3,203,000	$ 3,184,000	$ 3,090,000	$ 3,286,000
Pierson	Volusia	$ 32,183	$ 35,264	$ 35,675	$ 36,464	$ 37,976	$ 44,718	$ 42,348	$ 37,700	$ 40,299
Ponce Inlet	Volusia	$ 258,543	$ 262,641	$ 257,508	$ 254,049	$ 265,640	$ 292,496	$ 288,628	$ 282,913	$ 306,805
Port Orange	Volusia	$ 2,894,309	$ 2,967,560	$ 3,130,715	$ 2,903,612	$ 3,032,649	$ 3,408,623	$ 3,401,701	$ 3,314,238	$ 3,620,861
South Daytona	Volusia	$ 732,410	$ 736,579	$ 715,327	$ 699,932	$ 710,495	$ 773,158	$ 763,292	$ 732,553	$ 794,673
Sopchoppy	Wakulla	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Marks	Wakulla	$ 27,455	$ 25,460	$ 15,189	$ 26,188	$ 29,784	$ 34,923	$ 29,380	$ 27,355	$ 30,466
DeFuniak Springs	Walton	$ 263,733	$ 286,698	$ 403,948	$ 459,763	$ 466,623	$ 478,470	$ 502,715	$ 456,265	$ 463,590
Freeport	Walton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Paxton	Walton	$ -	$ 11,613	$ 12,880	$ 22,781	$ 15,061	$ 16,559	$ 15,764	$ 14,316	$ 14,700
Caryville	Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,008	$ 11,139	NR
Chipley	Washington	$ 201,425	$ 226,213	$ 224,543	$ 219,492	$ 221,433	$ 245,828	$ 248,241	$ 237,131	$ 241,695
Ebro	Washington	$ -	$ -	$ -	$ -	$ 42,428	$ 36,600	$ 36,600	$ 34,434	$ 37,009
Vernon	Washington	$ 30,921	$ 37,913	$ 34,259	$ 33,914	$ 33,560	$ 38,467	$ 39,623	$ 39,708	$ 39,494
Wausau	Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Municipal Public Service Tax-Electricity Totals		**$ 505,856,228**	**$ 522,270,643**	**$ 560,530,030**	**$ 581,414,018**	**$ 606,134,061**	**$ 668,376,661**	**$ 671,200,686**	**$ 666,317,873**	**$ 686,333,857**
% Change		**-**	**3.2%**	**7.3%**	**3.7%**	**4.3%**	**10.3%**	**0.4%**	**-0.7%**	**3.0%**
# Reporting		**305**	**308**	**318**	**318**	**325**	**328**	**335**	**334**	**327**
Total Municipal Public Service Taxes		**$ 741,201,140**	**$ 772,981,528**	**$ 808,793,559**	**$ 829,153,910**	**$ 912,265,351**	**$ 948,885,749**	**$ 830,044,048**	**$ 837,408,227**	**$ 864,080,636**
% Change		**-**	**4.3%**	**4.6%**	**2.5%**	**10.0%**	**4.0%**	**-12.5%**	**0.9%**	**3.2%**

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2013

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013
Electricity PST as % of All PST		**68.2%**	**67.6%**	**69.3%**	**70.1%**	**66.4%**	**70.4%**	**80.9%**	**79.6%**	**79.4%**

Notes:
1) This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 314.100 - Utility Service Tax - Electricity and 314.XXX - Utility Services Tax.
2) NR indicates those municipalities for which FY 2012-13 revenue data are not yet available. The FY 2012-13 account totals include the reported revenues of all Florida municipalities, except for the nine municipalities of Arcadia, Astatula, Caryville, Gretna, Groveland, Hampton, Quincy, Springfield, and Webster. This file will be updated in the future as these data become available.

Data Source: Florida Department of Financial Services.

TO AVOID PENALTY AND INTEREST CHARGES, THE REGULATORY ASSESSMENT FEE RETURN MUST BE FILED ON OR BEFORE «Field1»

Investor-Owned Electric Utility Regulatory Assessment Fee Return

Florida Public Service Commission

(See Filing Instructions on Back of Form)

STATUS:

____ Actual Return
____ Estimated Return
____ Amended Return

PERIOD COVERED:

«Field3»

«Field2»

FOR PSC USE ONLY

Check # ______________________

$ ______________ 06-02-002 003001

$ ______________ E

$ ______________ P 06-02-002 004011

$ ______________ I

Postmark Date ______________

Initials of Preparer ______________

Please Complete Below If Official Mailing Address Has Changed

(Name of Utility)	(Address)	(City/State)	(Zip)

LINE NO.	ACCOUNT CLASSIFICATION	INTRASTATE AMOUNTS	SALES FOR RESALE & INTERSTATE AMOUNTS	TOTAL REVENUES
1.	Sales of Electricity:			
2.	Residential Sales (440)	$	$	$
3.	Commercial Sales (442)			
	Industrial Sales (442)			
4.	Public Street and Highway Lighting (444)			
5.	Other Sales to Public Authorities (445)			
6.	Sales to Railroads and Railways (446)			
7.	Interdepartmental Sales (448)			
8.	**Total Sales to Ultimate Consumers**	$	$	$
9.	Sales for Resale (447)			
10.	**Total Sales of Electricity**	$	$	$
11.	Provision for Rate Refunds (449.1)			
12.	**Total Revenue Net of Refunds**	$	$	$
13.	OTHER OPERATING REVENUES:			
14.	Forfeited Discounts (450)			
15.	Miscellaneous Service Revenues (451)			
16.	Sales of Water and Water Power (453)			
17.	Rent from Electric Property (454)			
18.	Interdepartmental Rents (455)			
19.	Other Electric Revenues (456)			
20.	Deferred Fuel Revenues			
21.	Deferred Conservation Revenues			
22.	Unbilled Revenues			
23.	Other			
24.	**Total Other Operating Revenues**	$	$	$
25.	**Total Electric Operating Revenues**	$	$	$
26.	Adjustments: (Specify)			
27.				
28.				
29.				
30.				
31.				
32.	**Total Adjustments**	$		
33.	Revenues Subject to Regulatory Assessment Fee			
34.	**REGULATORY ASSESSMENT FEE RATE**	**.00072**		
35.	**REGULATORY ASSESSMENT FEE DUE** *(Line 33 x Line 34)*			
36.	**Less:** Payment for Jan. 1 – Jun. 30 Period	( )		
37.	**NET REGULATORY ASSESSMENT FEE DUE** *(see #2 on back)*			
38.	Penalty For Late Payment *(see #3 on back)*			
39.	Interest For Late Payment *(see #3 on back)*			
40.	Extension Payment Fee (see #4 on back)			
41.	**TOTAL AMOUNT DUE** (1)	$		

(1) As provided in Section 350.113, Florida Statutes, the **Minimum Annual Fee is $25** (see Item #5 on back)

I, the undersigned owner/officer of the above-named vendor, have read the foregoing and declare that to the best of my knowledge and belief the above information is a true and correct statement. I am aware that pursuant to Section 837.06, Florida Statutes, whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree.

(Signature of Utility Official) (Title) (Date)

(Please Print Name)

Telephone Number ( ) Fax Number ( )

F.E.I. No. ______________

PSC/AFD 68 (01/99)
Rule 25-6.0131, F.A.C.

FLORIDA PUBLIC SERVICE COMMISSION

Instructions For Filing Regulatory Assessment Fee Return
(Investor-Owned Electric Utility)

1. **WHEN TO FILE:** To avoid payment of penalties and interest, the Regulatory Assessment Fee Return and payment must be filed or postmarked:

   On or before July 30 for the six-month period January 1 through June 30, **and**
   On or before January 30 for the six-month period July 1 through December 31.

   However, if July 30 or January 30 falls on a Saturday, Sunday, or holiday, the Regulatory Assessment Fee Return may be filed or postmarked on the next business day, without penalty.

2. **FEES:** Each utility shall pay the currently authorized percentage, as indicated on Line 34 on the reverse side, of its gross operating revenues derived from intrastate business. Gross Operating Revenues are defined as the total revenues before expenses. The currently authorized percentage was implemented by Section 25-6.0131(1)(a), Florida Administrative Code. Annual revenue amounts are to be reported on the return for the period ended December 31.

3. **FAILURE TO FILE BY DUE DATE:** A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due. Failure to file a return by the established due date will result in a penalty being added to the amount of fee due, 5% for each 30 days or fraction thereof, not to exceed a total penalty of 25% (Line 38). In addition, interest shall be added in the amount of 1% for each 30 days or fraction thereof, not to exceed a total of 12% per year (Line 39).

4. **EXTENSION:** A utility, for good cause shown in a written request, may be granted up to a 30-day extension. A request must be made by filing the enclosed *Regulatory Assessment Fee Extension Request* form (PSC/AIT 124), two weeks prior to the filing date. If an extension is granted, a charge shall be added to the amount due:

   0.75% of the fee to be remitted for an extension of 15 days or less, *or*
   1.5% of the fee for an extension of 16 to 30 days.

   In lieu of paying the charges outlined above, a utility may file a return and remit payment based upon estimated gross operating revenues by checking the "Estimated Return" space in the top left-hand corner on the reverse side. If such return is filed by the normal due date, the utility shall be granted a 30-day extension period in which to file and remit the actual fee due without paying the above charges, provided the estimated fee payment remitted is at least 90% of the actual fee due for the period.

5. **REGULATORY ASSESSMENT FEE DUE:** Amounts are due and payable to the Commission by either January 30 or July 30 depending on the reporting period. If there are no revenues ***OR*** if revenues are insufficient to generate a minimum annual fee, remit the minimum fee. **A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due.**

6. **FEE ADJUSTMENTS:** Computational errors and/or differences in gross operating revenues reported for regulatory assessment fee purposes and those reported in the annual report may cause adjustments to amounts paid to the Commission. The utility will be notified as to the amount and reason for any adjustment. Penalty and interest charges may be applicable to additional amounts owed to the Commission by reason of the adjustment. A utility may file a written request for a refund of any overpayments. The request should be directed to Fiscal Services at the below-referenced address.

7. **MAILING INSTRUCTIONS:** Please complete this form, make a copy for your files, and return the original in the enclosed preaddressed envelope. Use of this envelope should assure a more accurate and expeditious recording of your payment. If you are unable to use the enclosed envelope, please address your remittance as follows:

   Florida Public Service Commission
   2540 Shumard Oak Boulevard
   Tallahassee, FL 32399-0850

   ATTENTION: Fiscal Services

8. **ADDITIONAL ASSISTANCE:** If any additional assistance is required in preparing the Regulatory Assessment Fee Return, please contact the Division of Accounting and Finance at (850) 413-6900 or at the above-referenced address, directing correspondence to the attention of the division.

TO AVOID PENALTY AND INTEREST CHARGES, THE REGULATORY ASSESSMENT FEE RETURN MUST BE FILED ON OR BEFORE «Field1»

Rural Electric Cooperative Regulatory Assessment Fee Return

Florida Public Service Commission

(See Filing Instructions on Back of Form)

STATUS:

______ Actual Return
______ Estimated Return
______ Amended Return

PERIOD COVERED:
«Field3»

«Field2»

FOR PSC USE ONLY

Check # ____________

$ ____________ 06-02-001 003001

$ ____________ E

$ ____________ P 06-02-001 004011

$ ____________ I

Postmark Date ____________
Initials of Preparer ____________

Please Complete Below If Official Mailing Address Has Changed

(Name of Utility) (Address) (City/State) (Zip)

LINE NO.	ACCOUNT CLASSIFICATION	INTRASTATE AMOUNTS	SALES FOR RESALE & INTERSTATE AMOUNTS	TOTAL REVENUES
1.	Sales of Electricity:			
2.	Residential Sales (440)	$	$	$
3.	Commercial Sales (442)			
	Industrial Sales (442)			
4.	Public Street and Highway Lighting (444)			
5.	Other Sales to Public Authorities (445)			
6.	Sales to Railroads and Railways (446)			
7.	Interdepartmental Sales (448)			
8.	**Total Sales to Ultimate Consumers**	$	$	$
9.	Sales for Resale (447)			
10.	**Total Sales of Electricity**	$	$	$
11.	Provision for Rate Refunds (449.1)			
12.	**Total Revenue Net of Refunds**	$	$	$
13.	Other Operating Revenues:			
14.	Forfeited Discounts (450)			
15.	Miscellaneous Service Revenues (451)			
16.	Sales of Water and Water Power (453)			
17.	Rent from Electric Property (454)			
18.	Interdepartmental Rents (455)			
19.	Other Electric Revenues (456)			
20.	**Total Other Operating Revenues**	$	$	$
21.	**Total Electric Operating Revenues**	$	$	$
22.	Adjustments: (Specify)			
23.		$		
24.				
25.				
26.				
27.				
28.	**Total Adjustments**	$		
29.	Revenues Subject to Regulatory Assessment Fee			
30.	**REGULATORY ASSESSMENT FEE RATE**	**.00015625**		
31.	**REGULATORY ASSESSMENT FEE DUE** *(Line 29 x Line 30)*			
32.	**Less:** Payment for Jan. 1 – Jun. 30 Period	( )		
33.	**NET REGULATORY ASSESSMENT FEE DUE** *(see #2 on back)*			
34.	Penalty For Late Payment *(see #3 on back)*			
35.	Interest For Late Payment *(see #3 on back)*			
36.	Extension Payment Fee (see #4 on back)			
37.	**TOTAL AMOUNT DUE**	$		

[1] As provided in Section 350.113, Florida Statutes, the **Minimum Annual Fee is $25** (see Item #5 on back)

I, the undersigned owner/officer of the above-named vendor, have read the foregoing and declare that to the best of my knowledge and belief the above information is a true and correct statement. I am aware that pursuant to Section 837.06, Florida Statutes, whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree.

(Signature of Utility Official) (Title) (Date)

(Please Print Name)

Telephone Number ( ) Fax Number ( )

F.E.I. No.

PSC/AFD 70 (07/96)
Rule 25-6.0131, F.A.C.

FLORIDA PUBLIC SERVICE COMMISSION

Instructions For Filing Regulatory Assessment Fee Return
(Rural Electric Cooperative)

1. **WHEN TO FILE:** To avoid payment of penalties and interest, the Regulatory Assessment Fee Return and payment must be filed or postmarked:

   On or before July 30 for the six-month period January 1 through June 30, **and**
   On or before January 30 for the six-month period July 1 through December 31.

   However, if July 30 or January 30 falls on a Saturday, Sunday, or holiday, the Regulatory Assessment Fee Return may be filed or postmarked on the next business day, without penalty.

2. **FEES:** Each utility shall pay the currently authorized percentage, as indicated on Line 30 on the reverse side, of its gross operating revenues derived from intrastate business. Gross Operating Revenues are defined as the total revenues before expenses. The currently authorized percentage was implemented by Section 25-6.0131(1)(b), Florida Administrative Code. Annual revenue amounts are to be reported on the return for the period ended December 31.

3. **FAILURE TO FILE BY DUE DATE:** A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due. Failure to file a return by the established due date will result in a penalty being added to the amount of fee due, 5% for each 30 days or fraction thereof, not to exceed a total penalty of 25% (Line 34). In addition, interest shall be added in the amount of 1% for each 30 days or fraction thereof, not to exceed a total of 12% per year (Line 35).

4. **EXTENSION:** A utility, for good cause shown in a written request, may be granted up to a 30-day extension. A request must be made by filing the enclosed *Regulatory Assessment Fee Extension Request* form (PSC/AIT 124), two weeks prior to the filing date. If an extension is granted, a charge shall be added to the amount due:

   0.75% of the fee to be remitted for an extension of 15 days or less, *or*
   1.5% of the fee for an extension of 16 to 30 days.

   In lieu of paying the charges outlined above, a utility may file a return and remit payment based upon estimated gross operating revenues by checking the "Estimated Return" space in the top left-hand corner on the reverse side. If such return is filed by the normal due date, the utility shall be granted a 30-day extension period in which to file and remit the actual fee due without paying the above charges, provided the estimated fee payment remitted is at least 90% of the actual fee due for the period.

5. **REGULATORY ASSESSMENT FEE DUE:** Amounts are due and payable to the Commission by either January 30 or July 30 depending on the reporting period. If there are no revenues ***OR*** if revenues are insufficient to generate a minimum annual fee, remit the minimum fee. **A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due.**

6. **FEE ADJUSTMENTS:** The utility will be notified as to the amount and reason for any adjustment. Penalty and interest charges may be applicable to additional amounts owed to the Commission by reason of the adjustment. A utility may file a written request for a refund of any overpayments. The request should be directed to Fiscal Services at the below-referenced address.

7. **MAILING INSTRUCTIONS:** Please complete this form, make a copy for your file, and return the original in the enclosed preaddressed envelope. Use of this envelope should assure a more accurate and expeditious recording of your payment. If you are unable to use the enclosed envelope, please address your remittance as follows:

   Florida Public Service Commission
   2540 Shumard Oak Boulevard
   Tallahassee, FL 32399-0850

   ATTENTION: Fiscal Services

8. **ADDITIONAL ASSISTANCE:** If any additional assistance is required in preparing the Regulatory Assessment Fee Return, please contact the Division of Accounting and Finance at (850) 413-6900 or at the above-referenced address, directing correspondence to the attention of the division.

TO AVOID PENALTY AND INTEREST CHARGES, THE REGULATORY ASSESSMENT FEE RETURN MUST BE FILED ON OR BEFORE «Field1»

Municipal Electric Utility Regulatory Assessment Fee Return

Florida Public Service Commission

(See Filing Instructions on Back of Form)

STATUS:

____ Actual Return
____ Estimated Return
____ Amended Return

PERIOD COVERED:
«Field3»

«Field2»

FOR PSC USE ONLY

Check # ____________

$ ____________ 06-02-001 003001

$ ____________ E

$ ____________ P 06-02-001 004011

$ ____________ I

Postmark Date ____________
Initials of Preparer ____________

Please Complete Below If Official Mailing Address Has Changed

(Name of Utility) (Address) (City/State) (Zip)

LINE NO.	ACCOUNT CLASSIFICATION	INTRASTATE AMOUNTS	SALES FOR RESALE & INTERSTATE AMOUNTS	TOTAL REVENUES
1.	Sales of Electricity:			
2.	Residential Sales (440)	$	$	$
3.	Commercial Sales (442)			
	Industrial Sales (442)			
4.	Public Street and Highway Lighting (444)			
5.	Other Sales to Public Authorities (445)			
6.	Sales to Railroads and Railways (446)			
7.	Interdepartmental Sales (448)			
8.	**Total Sales to Ultimate Consumers**	$	$	$
9.	Sales for Resale (447)			
10.	**Total Sales of Electricity**	$	$	$
11.	Provision for Rate Refunds (449.1)			
12.	**Total Revenue Net of Refunds**	$	$	$
13.	Other Operating Revenues:			
14.	Forfeited Discounts (450)			
15.	Miscellaneous Service Revenues (451)			
16.	Sales of Water and Water Power (453)			
17.	Rent from Electric Property (454)			
18.	Interdepartmental Rents (455)			
19.	Other Electric Revenues (456)			
20.	**Total Other Operating Revenues**	$	$	$
21.	**Total Electric Operating Revenues**	$	$	$
22.	Adjustments: (Specify)			
23.				
24.				
25.				
26.				
27.				
28.	**Total Adjustments**	$		
29.	Revenues Subject to Regulatory Assessment Fee			
30.	**REGULATORY ASSESSMENT FEE RATE**	**.00015625**		
31.	**REGULATORY ASSESSMENT FEE DUE** *(Line 29 x Line 30)*			
32.	**Less:** Payment for Jan. 1 – Jun. 30 Period	( )		
33.	**NET REGULATORY ASSESSMENT FEE DUE** *(see #2 on back)*			
34.	Penalty For Late Payment *(see #3 on back)*			
35.	Interest For Late Payment *(see #3 on back)*			
36.	Extension Payment Fee (see #4 on back)			
37.	**TOTAL AMOUNT DUE**	$		

(1) As provided in Section 350.113, Florida Statutes, the **Minimum Annual Fee is $25** (see Item #5 on back)

THIS FORM MUST BE COMPLETED AND RETURNED REGARDLESS OF THE AMOUNT OF REVENUES REPORTED

I, the undersigned owner/officer of the above-named vendor, have read the foregoing and declare that to the best of my knowledge and belief the above information is a true and correct statement. I am aware that pursuant to Section 837.06, Florida Statutes, whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree.

(Signature of Utility Official) (Title) (Date)

Telephone Number ( ) Fax Number ( )

(Please Print Name)

F.E.I. No.

PSC/AFD 69 (07/96)
Rule 25-6.0131, F.A.C.

FLORIDA PUBLIC SERVICE COMMISSION

Instructions For Filing Regulatory Assessment Fee Return
(Municipal Electric Utility)

1. **WHEN TO FILE:** To avoid payment of penalties and interest, the Regulatory Assessment Fee Return and payment must be filed or postmarked:

   On or before July 30 for the six-month period January 1 through June 30, **and**
   On or before January 30 for the six-month period July 1 through December 31.

   However, if July 30 or January 30 falls on a Saturday, Sunday, or holiday, the Regulatory Assessment Fee Return may be filed or postmarked on the next business day, without penalty.

2. **FEES:** Each utility shall pay the currently authorized percentage, as indicated on Line 30 on the reverse side, of its gross operating revenues derived from intrastate business. Gross Operating Revenues are defined as the total revenues before expenses. The currently authorized percentage was implemented by Section 25-6.0131(1)(b), Florida Administrative Code. Annual revenue amounts are to be reported on the return for the period ended December 31.

3. **FAILURE TO FILE BY DUE DATE:** A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due. Failure to file a return by the established due date will result in a penalty being added to the amount of fee due, 5% for each 30 days or fraction thereof, not to exceed a total penalty of 25% (Line 34). In addition, interest shall be added in the amount of 1% for each 30 days or fraction thereof, not to exceed a total of 12% per year (Line 35).

4. **EXTENSION:** A utility, for good cause shown in a written request, may be granted up to a 30-day extension. A request must be made by filing the enclosed *Regulatory Assessment Fee Extension Request* form (PSC/AIT 124), two weeks prior to the filing date. If an extension is granted, a charge shall be added to the amount due:

   0.75% of the fee to be remitted for an extension of 15 days or less, *or*
   1.5% of the fee for an extension of 16 to 30 days.

   In lieu of paying the charges outlined above, a utility may file a return and remit payment based upon estimated gross operating revenues by checking the “Estimated Return” space in the top left-hand corner on the reverse side. If such return is filed by the normal due date, the utility shall be granted a 30-day extension period in which to file and remit the actual fee due without paying the above charges, provided the estimated fee payment remitted is at least 90% of the actual fee due for the period.

5. **REGULATORY ASSESSMENT FEE DUE:** Amounts are due and payable to the Commission by either January 30 or July 30 depending on the reporting period. If there are no revenues ***OR*** if revenues are insufficient to generate a minimum annual fee, remit the minimum fee. **A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due.**

6. **FEE ADJUSTMENTS:** The utility will be notified as to the amount and reason for any adjustment. Penalty and interest charges may be applicable to additional amounts owed to the Commission by reason of the adjustment. A utility may file a written request for a refund of any overpayments. The request should be directed to Fiscal Services at the below-referenced address.

7. **MAILING INSTRUCTIONS:** Please complete this form, make a copy for your file, and return the original in the enclosed preaddressed envelope. Use of this envelope should assure a more accurate and expeditious recording of your payment. If you are unable to use the enclosed envelope, please address your remittance as follows:

   Florida Public Service Commission
   2540 Shumard Oak Boulevard
   Tallahassee, FL 32399-0850

   ATTENTION: Fiscal Services

8. **ADDITIONAL ASSISTANCE:** If any additional assistance is required in preparing the Regulatory Assessment Fee Return, please contact the Division of Accounting and Finance at (850) 413-6900 or at the above-referenced address, directing correspondence to the attention of the division.

SUMMARY

<u>QUESTION:</u>

You have requested that the Department issue formal advice outlining the tax consequences of net metering.

Net metering is a method of metering the energy consumed and produced at a home or a business that has its own renewable energy generator. Under net metering, excess electricity produced at a home or a business is used to offset the electricity received from a utility provider.

<u>ANSWER:</u>

Taxpayer should remit the gross receipt tax based on the amount of money received from its customers for charges for utility services. This would be the net amount of electricity billed to the customer after allowing a credit for the excess electricity generated by the customer and returned to the utility.

The retail sale of electrical power or energy in the State of Florida is subject to sales tax. The incidence of the tax is on "charges for electrical power or energy," and the tax rate for such sales is 7 percent. Therefore, if a customer is charged on the net electricity that it used during a particular billing cycle, the utility company should collect and remit the 7 percent sales tax on the amount billed to the customer.

March 31, 2009

XXX

Re: Technical Assistance Advisement 09A-014
Florida Gross Receipts Tax/Florida Sales and Use Tax
Net Metering
Sections 203.01, 212.05, 212.08(7)(j), Florida Statute (F.S.)
Rule 12A-1.039, Florida Administrative Code (F.A.C.)
Petitioner: XXX ("Taxpayer")

Dear XXX:

This letter is a response to your petition dated June 4, 2008, for the Department's issuance of a Technical Assistance Advisement ("TAA") concerning the above referenced party and matter. Your petition has been carefully examined and the Department finds it to be in compliance with the requisite criteria set forth in Chapter 12-11, F.A.C. This response to your request constitutes a TAA and is issued to you under the authority of s. 213.22, F.S.

<u>FACTS</u>

Some homes and businesses in Florida install equipment that produces electricity, which the home or business uses to reduce the amount of electricity required from the local electric utility.

When the home or business does not use the entire amount of electricity that it produces, the excess electricity is delivered to the electric utility for resale to other consumers.

At the end of the billing period, the electric utility will offset the amount of electricity it delivered to the home or business with the amount of electricity the home or business delivered to the electric utility. The electric utility only charges the consumer for the "net" amount of electricity provided to the home or business. The act of offsetting the electricity amounts is called "net metering," and Florida has recently required that utility providers implement net metering systems.

REQUESTED ADVISEMENTS

You have requested that the Department issue formal advice outlining the tax consequences of net metering.

ANALYSIS and DISCUSSION

Net metering is a method of metering the energy consumed and produced at a home or a business that has its own renewable energy generator. Under net metering, excess electricity produced at a home or a business is used to offset the electricity received from a utility provider.

Gross Receipts Tax

Section 203.01, F.S., imposes the gross receipts tax on the total amount of gross receipts **received** by a distribution company for utility services. [Emphasis supplied] The rate applied to utility services is 2.5 percent. Assuming the electric utility is a distribution company, it would be required to pay gross receipts tax on its total receipts from **charges** for utility service sold to a retail consumer. If the customer pays $100 on the net electricity that the consumer purchased, the distribution company is taxed on the $100 received.

Taxpayer should remit the gross receipt tax based on the amount of money received from its customers for charges for utility services. This would be the net amount of electricity billed to the customer after allowing a credit for the excess electricity generated by the customer and returned to the utility. In other words, if the bill from the utility shows electricity consumed by the customer in the amount of $100 and a credit for excess customer-generated electricity in the amount $25, resulting in a balance due of $75, gross receipts tax is calculated on the net amount or $75.

Sales and Use Tax

Section 212.05, F.S., provides it is the legislative intent that every person is exercising a taxable privilege that engages in the business of selling tangible personal property at retail in this state. For exercising such a privilege, a tax is levied on each taxable transaction or incident. The retail sale of electrical power or energy in the State of Florida is subject to sales tax. The incidence of the tax is on "charges for electrical power or energy," and the tax rate for such sales is 7 percent. See Section 212.05(1)(e)1.c., F.S. Therefore, if a customer is charged $100 on the net electricity that it used during a particular billing cycle, the utility company should collect and remit the 7 percent sales tax on the $100 amount billed to the customer. Electricity that is provided to the customer before net metering would not be taxed. Although we are sure that you are well aware of this, we note that sales of electricity to residential households are exempt from sales tax pursuant to Section 212.08(7)(j), F.S.

Excess customer-generated electrical power or energy put on the grid is ultimately used by and billed to Taxpayer's other customers. Credits allowed by Taxpayer for such excess customer-generated electrical power or energy would be treated as exempt sales for resale under the provisions of Rule 12A-1.039, F.A.C.
Under the same scenario above, Florida sales and use tax would be calculated at the tax rate of 7 percent on the charge of $75.

CONCLUDING STATEMENT

This response constitutes a Technical Assistance Advisement under Section 213.22, F.S., which is binding on the Department only under the facts and circumstances described in the request for this advice, as specified in Section 213.22, F.S. Our response is predicated on those facts and the specific situation summarized above. You are advised that subsequent statutory or administrative rule changes or judicial interpretations of the statutes or rules upon which this advice is based may subject similar future transactions to a different treatment than expressed in this response.

You are further advised that this response, your request and related backup documents are public records under Chapter 119, F.S., and are subject to disclosure to the public under the conditions of Section 213.22, F.S. Confidential information must be deleted before public disclosure. In an effort to protect confidentiality, we request you provide the undersigned with an edited copy of your request for Technical Assistance Advisement, the backup material and this response, deleting names, addresses and any other details which might lead to identification of the taxpayer. Your response should be received by the Department within 10 days of the date of this letter.

If you have any further questions with regard to this matter and wish to discuss them, you may contact me directly at 850-488-8026.

Kind Regards,

Alan R. Fulton
Tax Law Specialist
Technical Assistance & Dispute Resolution

ARF\lp
Record ID: 46454

SUMMARY

QUESTION:

You have requested that the Department issue formal advice outlining the tax consequences of net metering for electric cooperatives.

Net metering is a method of metering the energy consumed and produced at a home or a business that has its own renewable energy generator. Under net metering, excess electricity produced at a home or a business is used to offset the electricity received from a utility provider.

ANSWER:

Taxpayer should remit the gross receipt tax based on the amount of money received from its customers for charges for utility services. This would be the net amount of electricity billed to the customer after allowing a credit for the excess electricity generated by the customer and returned to the utility.

The retail sale of electrical power or energy in the State of Florida is subject to sales tax. The incidence of the tax is on "charges for electrical power or energy," and the tax rate for such sales is 7 percent. Therefore, if a customer is charged on the net electricity that it used during a particular billing cycle, the utility company should collect and remit the 7 percent sales tax on the amount billed to the customer.

June 24, 2009

XXX

Re: Technical Assistance Advisement 09A-029
Sales and Use Tax/Gross Receipts Tax – Net Metering
Sections: 203.01, 212.05, 212.08, 212.06, Florida Statutes (F.S.)
Rule: 12A-1.039, Florida Administrative Code (F.A.C.)
Petitioner: XXX. ("Taxpayer")

Dear XXX:

This letter is a response to your petition dated March 14, 2008, for the Department's issuance of a Technical Assistance Advisement ("TAA") concerning the above referenced party and matter. Your petition has been carefully examined and the Department finds it to be in compliance with the requisite criteria set forth in Chapter 12-11, F.A.C. This response to your request constitutes a TAA and is issued to you under the authority of s. 213.22, F.S.

FACTS

Taxpayer is the XXX XXX for XXX XXX XXX (XXX-XXX and XXX-XXX) who provide energy and electricity in Florida. Taxpayer XXX are XXX XXX who sell electricity at retail to XXX XXX and buy their power from XXX XXX providers or other utilities. XXX XXX buy their power from other utilities and would directly buy back any excess power from a renewable generator. The XXX XXX XXX buys the excess power from the customer under their arrangement with the other XXX XXXs. For this reason, Taxpayer request will consist of issues which apply to all XXX XXX; issues which apply only to the XXX XXX who buy power from XXX XXX XXX; and issues which apply only to the XXX XXXs who buy power from other utilities.

Some of Taxpayer’s XXXs own and operate small XXX XXX. To date, most of these are (less than 10kW) XXX (XXX) energy systems. Several of Taxpayer’s XXX offer a net billing option, which allows customers to receive credits for excess electricity generated by their renewable generator. "Excess" electricity is the electricity that is generated by the customer that exceeds the customer's needs at that moment.

The metering/billing process is a multi-step transaction. Generally, after a customer notifies the distribution XXX that he or she would like to interconnect a renewable generator to the XXX's facilities, the XXX sends the customer a third-party interconnection agreement and request for verification of insurance. Under the terms of the interconnection agreement, any excess electricity generated by the customer is sold to the XXX XXX provider. [your emphasis] Once the distribution XXX receives the executed documents, the customer's meter is changed out for a special meter (unless the customer's meter is already capable of measuring electricity in both directions) that measures both the amount of electricity supplied by the distribution XXX to the customer and the excess electricity generated by the customer that is delivered to the XXX XXX.

The customer's account is set up to reflect the tariffed retail rate paid by the customer to the distribution XXX and the rate paid by the XXX XXX to the customer (these rates may not be the same) for the excess electricity. The excess power delivered from the customer to the XXX XXX is then resold to the distribution XXX. The resale of excess electricity generated by the customer to the XXX XXX is shown as a credit on the distribution XXX's XXX power bill. In turn, the distribution XXX reflects the credit on the customer's bill.

REQUESTED ADVISEMENTS

I. For all 15 XXXs, Taxpayer has asked advice regarding the following:

> Issue 1: Is the electricity sold to a residential customer that has provided an exemption certificate to the XXX still exempt from sales tax on electricity under the household fuel exemption in Section 212.08(7)(j), F.S., even though the customer is now in the business of selling electricity?
>
> Issue 2: Most renewable generators require the use of inverters on their systems. The utility supplies a small amount of electricity to these inverters. When the utility sells electricity that is used directly by the renewable generation system, is the residential customer’s status changed to commercial for tax purposes?
>
> Issue 3: Does the XXX have any sales tax liability for power generated and consumed by the customer that does not register on the XXX’s meter (i.e., that is not excess power)?

Issue 4: Does the XXX have any gross receipts tax liability for power generated and consumed by the customer that does not register on the XXX's meter (i.e., that is not excess power)?

Issue 5: What is the proper method to calculate sales and gross receipts taxes for residential and commercial customers utilizing net billing (Can the distribution XXX apply the Net Billing Credit before the sales taxes are calculated and should it offset the distribution XXX's revenues for calculating its gross receipts tax)?

II. For the 13 XXXs, with XXX XXX power contracts, Taxpayer has asked advice regarding the following:

Issue 1: Is the sale of customer's excess electricity to the XXX XXX exempt from sales taxes as a sale for resale?

Issue 2: Is the sale of excess electricity from customer to the XXX XXX exempt from gross receipts tax as a sale for resale?

III. For the 2 XXXs, with power contracts with other utilities, Taxpayer has asked advice regarding the following:

Issue 1: Is the sale of customer's excess electricity directly to the distribution XXX exempt from sales taxes as a sale for resale?

Issue 2: Is the sale of excess electricity directly from the customer to the distribution XXX exempt from gross receipts tax as a sale for resale?

ANALYSIS and DISCUSSION

Gross Receipts Tax

Section 203.01, F.S., imposes the gross receipts tax on the total amount of gross receipts **received** by a distribution company for utility services. [Emphasis supplied] The rate applied to utility services is 2.5 percent. Assuming the electric utility is a distribution company, it would be required to pay gross receipts tax on its total receipts from **charges** for utility service sold to a retail consumer. If the customer pays $100 on the net electricity that the consumer purchased, the distribution company is taxed on the $100 received.

Taxpayer's XXX should remit the gross receipt tax based on the amount of money that they receive from its customers for charges for utility services. This would be the net amount of electricity billed to the customer after allowing a credit for the excess electricity generated by the customer and returned to the utility.

Sales and Use Tax

Section 212.05, F.S., provides it is the legislative intent that every person is exercising a taxable privilege that engages in the business of selling tangible personal property at retail in this state. For exercising such a privilege, a tax is levied on each taxable transaction or incident. The retail sale of electrical power or energy in the State of Florida is subject to sales tax. The incidence of the tax is on “charges for electrical power or energy,” and the tax rate for such sales is 7 percent. See Section 212.05(1)(e)1.c, F.S. Therefore, if a customer is charged $100 on the net electricity that it used during a particular billing cycle, the utility company should collect and remit the 7 percent sales tax on the $100 amount billed to the customer. Electricity that is provided to the customer before net metering would not be taxed. Although we are sure that you are well aware of this, we note that sales of electricity to residential households are exempt from sales tax pursuant to Section 212.08(7)(j), F.S.

Excess customer-generated electrical power or energy put on the grid is ultimately used by and billed to other customers of Taxpayer’s XXX. Credits allowed by Taxpayer’s XXX for such excess customer-generated electrical power or energy would be treated as exempt sales for resale under the provisions of Rule 12A-1.039, F.A.C.
Under the facts presented in your letter, residential customers are not required to register as dealers with the Department and be responsible for all of the attendant responsibilities that go along with being a "dealer." The residential customer's delivery of excess electricity and the subsequent credit or "net-billing" do not defeat the exemption provided to residential customers. This conclusion also considers: (a) that the delivery of excess electricity is a "sale for resale" that carries out the Legislature's intent of promoting energy conservation and the use of solar energy; and, (b) under the facts presented, Florida sales tax would not be due because the customer to utility "sale" is an exempt "sale for resale," and Florida gross receipts tax would not be due because the "sale" is not to a "retail consumer."

RESPONSE

Section I:

Issue 1: Is the electricity sold to a residential customer that has provided an exemption certificate to the XXX still exempt from sales tax on electricity under the household fuel exemption in Section 212.08(7)(j), F.S., even though the customer is now in the business of selling electricity?

Response**:** Yes. The exemption for residential households is not defeated. The Department does not issue "exemption certificates" to residential households.

Issue 2: Most renewable generators require the use of inverters on their systems. The utility supplies a small amount of electricity to these inverters. When the utility sells electricity that is used directly by the renewable generation system, is the residential customer’s status changed to commercial for tax purposes?

Response: No. The status of the customer would not change to commercial for tax purposes.

Issue 3: Does the XXX have any sales tax liability for power generated and consumed by the customer that does not register on the XXX's meter (i.e., that is not excess power)?

Response**:** No. The XXX would not be responsible for tax on power generated and consumed by its customer that is not registered on the XXX's meter.

Issue 4: Does the XXX have any gross receipts tax liability for power generated and consumed by the customer that does not register on the XXX's meter (i.e., that is not excess power)?

Response**:** No, the XXX would not be liable.

Issue 5: What is the proper method to calculate sales and gross receipts taxes for residential and commercial customers utilizing net billing (Can the distribution XXX apply the Net Billing Credit before the sales taxes are calculated and should it offset the distribution XXX's revenues for calculating its gross receipts tax)?

Response**:** Florida gross receipts tax is levied against the total amount of gross receipts **received** by a distribution company. [emphasis supplied] *See* Section 203.01(1)(c), F.S. The XXXs should remit gross receipts tax based on the gross receipts they actually receive (and bill for what they will actually be receiving). In other words, if the bill from the utility shows electricity consumed by the customer in the amount of $XXX and a credit for excess customer-generated electricity in the amount $XXX, resulting in a balance due of $XXX, gross receipts tax, for purposes of calculating the gross receipts tax, is calculated on the net amount or $XXX. Under the same scenario, Florida sales and use tax would be calculated at the tax rate of XXX percent on the charge of $XXX. Electricity that is provided to the customer before net metering would not be taxed. Sales tax would only apply to sales to commercial customers; all sales to residential customers are specifically exempt from sales tax.

<u>Section II:</u>

Issue 1: Is the sale of customer's excess electricity to the XXX XXX exempt from sales taxes as a sale for resale?

Response: Yes. The sale of customer's excess electricity to the XXX XXX would be exempt from sales taxes as a sale for resale pursuant to Section 212.06(1)(b), F.S.

Issue 2: Is the sale of excess electricity from customer to the XXX XXX exempt from gross receipts tax?

Response: Yes. The gross receipts tax is not imposed on the sale or delivery of electricity to XXXs for resale, pursuant to Section 203.01(3)(a)2., F.S.

Section III:

Issue 1: Is the sale of customer's excess electricity directly to the distribution XXX exempt from sales taxes as a sale for resale?

Response: Yes. The sale of customer's excess electricity to the XXX XXX would be exempt from sales taxes as a sale for resale pursuant to Section 212.06(1)(b), F.S.

Issue 2: Is the sale of excess electricity directly from the customer to the distribution XXX exempt from gross receipts tax?

Response: Yes. The gross receipts tax is not imposed on gross receipts received from the sale or delivery of electricity to XXXs for resale, pursuant to Section 203.01(3)(a)2., F.S.

CONCLUDING STATEMENT

This response constitutes a Technical Assistance Advisement under Section 213.22, F.S., which is binding on the Department only under the facts and circumstances described in the request for this advice, as specified in Section 213.22, F.S. Our response is predicated on those facts and the specific situation summarized above. You are advised that subsequent statutory or administrative rule changes or judicial interpretations of the statutes or rules upon which this advice is based may subject similar future transactions to a different treatment than expressed in this response.

You are further advised that this response, your request and related backup documents are public records under Chapter 119, F.S., and are subject to disclosure to the public under the conditions of Section 213.22, F.S. Confidential information must be deleted before public disclosure. In an effort to protect confidentiality, we request you provide the undersigned with an edited copy of your request for Technical Assistance Advisement, the backup material and this response, deleting names, addresses and any other details which might lead to identification of the taxpayer. Your response should be received by the Department within 10 days of the date of this letter.

If you have any further questions with regard to this matter and wish to discuss them, you may contact me directly at 850-488-8026.

Kind Regards,

Alan R. Fulton
Tax Law Specialist
Technical Assistance & Dispute Resolution

ARF\lp
Record ID: 43389

FLORIDA
DEPARTMENT OF REVENUE
Executive Director
Lisa Echeverri

December 10, 2007

Ms. Michelle Hershel
Director, Regulatory Affairs
Florida Electric Cooperative Association, Inc.
2916 Apalachee Parkway
Tallahassee, FL 32301

Re. Letter of Technical Advice 07A-1462
Florida Electric Cooperatives Association
Gross Receipts Tax and Sales Tax – Tax Calculation on Net Billing Credits involving residential solar energy systems
Sections 203.01, 212.02, 212.06, 212.08, and 366.81, F.S. ("Florida Statutes")
Rule 25-6.065(6), F.A.C. ("Florida Administrative Code")

Dear Ms. Hershel.

Pursuant to Rule 12-11.003, F.A.C., taxpayers may seek informal written technical advice from the Department of Revenue ("Department"). Such advice is issued in the form of a Letter of Technical Advice ("LTA"). This LTA is being issued in response to your written request for informal guidance of August 7, 2007, concerning the delivery of excess electricity (generated by solar energy systems) from residential customers to electric utilities. Please note that this LTA constitutes the opinion of the writer only and does not represent the official position of the Department.

REQUESTED ADVISEMENT

You request clarification on the collection of sales tax and gross receipts tax when a residential customer interconnects a photovoltaic ("PV") electric system (i.e., solar energy system) with a cooperative's facilities. Your letter provides, in part, the following:

> Issue 1 Is the electricity sold to a residential customer that has provided an exemption certificate to the cooperative still exempt from sales tax on electricity under the household fuel exemption in Section 212.08(7)(j), F.S., even though the customer is now in the business of selling electricity?
>
> Issue 2: Is the sale of the customer's excess electricity to the wholesale cooperative exempt from sales taxes as a sale for resale?

Issue 3: Is the sale of excess electricity from the customer to the wholesale cooperative exempt from gross receipts tax as a sale for resale?

Issue 4: Does the cooperative have any sales tax liability for power generated and consumed by the customer that does not register on the cooperative's meter (i.e., that is not excess power)?

Issue 5. Does the cooperative have any gross receipts tax liability for power generated and consumed by the customer that does not register on the cooperative's meter (i e., that is not excess power)?

Issue 6: What is the proper method to calculate sales and gross receipts taxes for residential and commercial customers utilizing net billing (Can the distribution cooperative apply the Net Billing Credit before the sales taxes are calculated and should it offset the distribution cooperative's revenues for calculating its gross receipts tax)?

FACTS

Your letter of August 7, 2007, provides, in part:

* * *

Some .. customers own and operate small (less than 10kW) PV energy systems. [Certain electric cooperatives] ["the cooperatives"] offer a net billing option which allows customers to receive credits for excess electricity generated by their PV system. "Excess" electricity is the electricity that is generated by the customer that exceeds the customer's needs at that moment.

The metering/billing process is a multi-step transaction. Generally, after a customer notifies the cooperative that they would like to interconnect a PV electric system to the cooperative's facilities, the cooperative sends the customer an interconnection agreement and request for verification of insurance. Under the terms of the interconnection agreement, any excess electricity generated by the customer is sold to the **wholesale** cooperative provider. Once the distribution cooperative receives the executed documents, the customer's meter is changed out for a special meter (unless the customer's meter is already capable of measuring electricity in both directions) that measures both the amount of electricity supplied by the distribution cooperative to the customer and the excess electricity generated by the customer that is delivered to the wholesale cooperative.

The customer's account is set up to reflect the tariffed retail rate paid by the customer to the distribution cooperative and the rate paid by the wholesale cooperative to the customer (these rates may not be the same) for the excess electricity The excess power delivered from the customer to the wholesale cooperative is then resold to the distribution cooperative The resale of excess electricity generated by the customer to the wholesale cooperative is shown as a credit on the distribution cooperative's wholesale power bill In

> turn, the distribution cooperative reflects the credit on the customer's bill. [emphasis in original]

* * *

The Florida Public Service Commission exercises regulatory authority over utilities Rule 25-6.065(6), F.A.C., governs the Interconnection of Small Photo Voltaic Systems. While the Rules of the Florida Public Service Commission do not guide us on Florida tax questions, this particular rule is relevant to our analysis because it provides for "net billing" and crediting The rule provides, in part:

> The utility may install an additional meter or metering equipment on the customer's premises capable of measuring any excess kilowatt-hours produced by the SPS [a small photovoltaic system] and delivered back to the utility. .. The value of such excess generation **shall be credited to the customer's bill** . . If the utility does not install such a meter or metering equipment, the utility **shall** permit the customer to net meter any excess power delivered to the utility by a single standard watt-hour meter capable of reversing directions to offset recorded consumption by the customer. If the kilowatt-hour of energy produced by the SPS exceeds the customer's kilowatt-hour consumption for any billing period, such that when the meter is read the value displayed on the register is less than the value displayed on the register when it was read at the end of the previous billing period, the utility **shall carry forward credit for the excess energy to the next billing period.** Credits may accumulate and be carried forward for a 12-month period specified by the utility in the SPS Interconnection Agreement. **In no event shall the customer be paid for excess energy delivered to the utility at the end of the 12-month period. [emphasis added]**

RESPONSE

This response is based on the specific facts and circumstances presented in your letter. This response does not consider situations involving "co-generation," "small power producers," "industrial manufacturing" or persons who produce electricity as a substitute for electricity produced by a utility (except as to your specific question in Issues 4 and 5)

Generally:

There are several things to consider when responding to the issues you present in your letter

The first is determining whether the residential customer is "in the business" of selling electricity when it delivers excess electricity to the cooperative and receives a credit (or economic benefit under "net-billing") If so, the next question begs does this then defeat the exemption on the initial "cooperative to customer sale" for residential households?

"Business" is defined broadly at Section 212 02(2), F S It could be said that residential customers, under the facts presented, are "in the business" of selling excess electricity back to the cooperatives because the residential customers are engaged in an activity for private gain or benefit (such a residential customer likely says at some point "any excess electricity my PV generates, the cooperative must buy it back, and I will get a credit on my overall electric bill").

Next, if a residential customer is "in the business" of selling electricity and a "sale" is occurring (as that term if broadly defined at Section 212.02(15), F.S.), then arguably, the residential customer must register with the Department as a "dealer" (as that term is defined in Section 212 06(2), F.S

Further, if a residential customer is "in the business" of selling electricity, then is the sale an exempt sale for resale because the cooperative will be reselling the electricity that it "bought" from the residential customer? The answer is: "yes." Your letter provides that under the terms of the interconnection agreements, any excess electricity generated by the residential customer is sold to the **wholesale** cooperative provider who then gives the **distribution** cooperative a credit on its bill.

But do these determinations involving "in the business" and "sales for resale" defeat the exemption enjoyed by residential customers under these facts. The answer is "no" for several reasons.

First, Section 212.08(7)(j), F.S., provides that the exemption is defeated if the utilities sold "are used" for a nonexempt purpose Under these facts, the utilities sold by the cooperatives continue to be used for residential purposes by the residential households The selling of excess electricity by the residential customer does not constitute a "use."

Secondly, we find it significant that utilities such as the cooperatives are required to credit and "net-bill" when residential customers deliver excess electricity to them As we observed earlier, the Rules of the Florida Public Service Commission (and for that matter, Chapter 366, F.S. -- except for any specific provisions that involve the Department or laws it is charged to administer) do not direct the Department or the public on tax matters. However, the Department is mindful and respectful of the Legislative intent specifically provided for in Section 366.81, F S Rule 25-6.065(6), F.A.C., implements this Legislative intent Section 366.81, F.S., provides, in part:

> The Legislature finds that it is critical to utilize the most efficient and cost-effective energy conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens. ... The Legislature further finds that the Florida Public Service Commission is the appropriate agency to adopt goals and approve plans related to the conservation of electric energy .... [T]he Legislature intends that the use of solar energy ... be encouraged . .

Under the facts presented in your letter, reading Sections 212.08(7)(j) and 366.81, F S , together leads to the conclusion that it would be impractical and unreasonable to require residential customers (under these facts) to register as "dealers" with the Department and be responsible for all of the attendant responsibilities that go along with being a "dealer " The residential customer's delivery of excess electricity and the subsequent credit or "net-billing" does not defeat the exemption provided to residential customers. This conclusion also considers: (a) that the delivery of excess electricity is a "sale for resale" that carries out the Legislature's intent of promoting energy conservation and the use of solar energy; and (b) under the facts presented, Florida Sales Tax would not be due because the customer to cooperative "sale" is an exempt "sale for resale" and Florida Gross Receipts Tax would not be due because the "sale" is not to a "retail consumer "

Based on the discussion above, the Department turns to your specific issues.

Issue 1: Is the electricity sold to a residential customer that has provided an exemption certificate to the cooperative still exempt from sales tax on electricity under the household fuel exemption in Section 212 08(7)(j), F.S., even though the customer is now in the business of selling electricity?

Response: Yes The exemption for residential households is not defeated The Department does not issue "exemption certificates" to residential households

Issue 2: Is the sale of the customer's excess electricity to the wholesale cooperative exempt from sales taxes as a sale for resale?

Response: Yes. The "customer to cooperative" sale is a "sale for resale" and is exempt from Florida Sales Tax.

Issue 3: Is the sale of excess electricity from the customer to the wholesale cooperative exempt from gross receipts tax as a sale for resale?

Response: Yes, but more fundamentally, it is not subject to Florida Gross Receipts Tax because the sale is not to a retail customer.

Issue 4: Does the cooperative have any sales tax liability for power generated and consumed by the customer that does not register on the cooperative's meter (i.e., that is not excess power)?

Response: A residential customer would still be exempt from Florida Sales and Use Tax A commercial customer would be liable for use tax calculated on the cost price. *See* Section 212.06(1)(b), F.S However, the commercial customer would be responsible for complying in that situation, not the cooperative.

Issue 5: Does the cooperative have any gross receipts tax liability for power generated and consumed by the customer that does not register on the cooperative's meter (i e , that is not excess power)?

Response: No, the cooperative would not be liable, but the customer would be. Section 203.01(1)(i), F.S., provides

> Any person other than a cogenerator or small power producer described in paragraph (h) who produces for his or her own use electrical energy which is a substitute for electrical energy produced by an electric utility as defined in s. 366.02 is subject to the tax imposed by this section. The tax shall be applied to the cost price of such electrical energy as provided in s. 212.02(4) and shall be paid each month. The provisions of this paragraph do not apply to any electrical energy produced and used by an electric utility.

__Issue 6:__ What is the proper method to calculate sales and gross receipts taxes for residential and commercial customers utilizing net billing (Can the distribution cooperative apply the Net Billing Credit before the sales taxes are calculated and should it offset the distribution cooperative's revenues for calculating its gross receipts tax)?

Response: Florida Gross Receipts Tax is levied against the total amount of gross receipts ***received*** *by a distribution company. [emphasis supplied]* *See* Section 203.01(1)(c), F.S. The cooperatives should remit Gross Receipts Tax based on what they actually receive (and bill for what they will actually be receiving). In other words, if the bill to the customer is initially $100.00 but after credits is $75.00, Gross Receipts Tax would be due on the $75.00 because that is the total amount that is (or will be) received by the cooperatives.

Sales of electricity to residential households are exempt from Florida Sales Tax. Likewise, as discussed above, a "sale for resale" is exempt from Florida Sales Tax. So for Florida Sales Tax purposes, how the customer is billed (in situations like the ones presented in your letter) is of no real consequence because no Florida Sales Tax is due on either of the transactions (the cooperative to customer sale and subsequently, the customer to cooperative sale).

As noted in the first paragraph of this letter, this LTA is being issued in response to the disclosed facts and circumstances of your specific situation, and it does not constitute the official position of the Department. Rather, this letter represents the opinion of the writer only. If you wish an official binding statement, you may file a written request for a Technical Assistance Advisement. Rule Chapter 12-11, F.A.C., outlines the procedure to follow in making this request. This rule chapter of the Florida Administrative Code can be found at http://www.myflorida.com/dor/law/. Any request for a Technical Assistance Advisement should be sent to Technical Assistance and Dispute Resolution, Department of Revenue, P.O. Box 7443, Tallahassee, Florida, 32314-7443.

If you have any further questions with regard to this matter and wish to discuss them, you may contact me directly at (850) 922-4714.

Sincerely,

Eric Russell Peate
Senior Attorney
Technical Assistance & Dispute Resolution

Record ID 34460

533 So.2d 281 (1988)

PW VENTURES, INC., Appellant,
v.
Katie NICHOLS, Chairman of Florida Public Service Commission, and Florida Public Service Commission, Appellees.

No. 71462.

Supreme Court of Florida.

October 27, 1988.

282*282 Richard D. Melson of Hopping, Boyd, Green & Sams, Tallahassee, for appellant.

Susan F. Clark, Gen. Counsel, Florida Public Service Com'n, Tallahassee, for appellees.

Richard A. Zambo and Paul Sexton of Richard A. Zambo, P.A., Brandon, for amici curiae, C.F. Industries, Inc., IMC Fertilizer, Inc., Monsanto Co. and W.R. Grace & Co.

GRIMES, Justice.

PW Ventures, Inc. (PW Ventures) appeals from an adverse ruling of the Florida Public Service Commission (PSC). We have jurisdiction. Art. V, § 3(b)(2), Fla. Const.

PW Ventures[1] signed a letter of intent with Pratt and Whitney (Pratt) to provide electric and thermal power at Pratt's industrial complex in Palm Beach County. PW Ventures proposes to construct, own, and operate a cogeneration[2] project on land leased from Pratt and to sell its output to Pratt under a long-term take or pay contract.[3] Before proceeding with construction of the facility that would provide the power, PW Ventures sought a declaratory statement from the PSC that it would not be a public utility subject to PSC regulation. After a hearing, the PSC ruled that PW Ventures proposed transaction with Pratt fell within its regulatory jurisdiction.

At issue here is whether the sale of electricity to a single customer[4] makes the provider a public utility. The decision hinges on the phrase "to the public," as it is used in section 366.02(1), Florida Statutes (1985). In pertinent part that subsection provides:

"Public utility" means every person, corporation, partnership, association, or other 283*283 legal entity and their lessees, trustees, or receivers supplying electricity or gas (natural, manufactured, or similar gaseous substance) to or for the public within this state... .

Distilled to their essence, the parties' views are as follows: PW Ventures says the phrase "to the public" means to the general public and was not meant to apply to a bargained-for transaction between two businesses. The PSC says the phrase means "to any member of the public." While the issue is not without doubt, we are inclined to the position of the PSC.

At the outset, we note the well established principle that the contemporaneous construction of a statute by the agency charged with its enforcement and interpretation is entitled to great weight. *Warnock v. Florida Hotel & Restaurant Comm'n,* 178 So.2d 917 (Fla. 3d DCA 1965), *appeal dismissed,* 188 So.2d 811 (Fla. 1966). The courts will not depart from such a construction unless it is clearly unauthorized or erroneous. *Gay v. Canada Dry Bottling Co.,* 59 So.2d 788 (Fla. 1952).

Also, it is significant that the statute itself would permit the type of transaction proposed by PW Ventures and Pratt to be unregulated if it were for natural gas services. Section 366.02(1) provides the following exemption: "[T]he term `public utility' as used herein does not include ... any natural gas pipeline transmission company making only sales of natural gas at wholesale and to direct industrial consumers... ." The legislature did not provide a similar exemption for electricity. The express mention of one thing implies the exclusion of another. *Thayer v. State,* 335 So.2d 815 (Fla. 1976).

This rationale is further illustrated in the statutory regulation of water and sewer utilities. As explained in the PSC order:

In parallel with Section 366.02(1), Section 367.021, Florida Statutes (1985), defines a water or sewer utility as every person "providing, or who proposes to provide, water or sewer service to the public for compensation." Section 367.022(6), Florida Statutes, expressly exempts from this definition "systems with the capacity or proposed capacity to serve 100 or fewer persons". There is not a parallel numerical exemption to the statutory definition of a public utility supplying electricity. Yet the statutory interpretation advocated by PW Ventures would require a line to be drawn somewhere between sales to some members of the public, as a presumably nonjurisdictional activity, and sales to the public generally and indiscriminately, an admittedly jurisdictional activity.

Moreover, the PSC's interpretation is consistent with the legislative scheme of chapter 366. The regulation of the production and sale of electricity necessarily contemplates the granting of monopolies in the public interest. *Storey v. Mayo,* 217 So.2d 304 (Fla. 1968), *cert. denied,* 395 U.S. 909, 89 S.Ct. 1751, 23 L.Ed.2d 222 (1969). Section 366.04(3), Florida Statutes (1985), directs the PSC to exercise its powers to avoid "uneconomic duplication of generation, transmission, and distribution facilities." If the proposed sale of electricity by PW Ventures is outside of PSC jurisdiction, the duplication of facilities could occur. What PW Ventures proposes is to go into an area served by a utility and take one of its major customers.[5] Under PW Ventures' interpretation, other ventures could enter into similar contracts with other high use industrial complexes on a one-to-one basis and drastically change the regulatory scheme in this state. The effect of this practice would be that revenue that otherwise would have gone to the regulated utilities which serve the affected areas would be diverted to unregulated producers. This revenue would have to be made up by the remaining customers of the regulated utilities since the fixed costs of the regulated systems would not have been reduced.

284*284 We do not believe that *Fletcher Properties v. Florida Public Service Commission,* 356 So.2d 289 (Fla. 1978), mandates a different result. In that case, we did approve a PSC order which included reasoning to the effect that service to the public meant service to the indefinite public or to all individuals within a given area. However, the case did not arise in the context of a sale to a single customer. We simply affirmed the PSC's determination that the developer and owner of lines and lift stations who proposed to furnish water and sewer service to single family homes at the same rate as it was charged by the area water and sewer utility occupied the status of a public utility.[6]

The fact that the PSC would have no jurisdiction over the proposed generating facility if Pratt exercised its option under the letter of intent to buy the facility and elected to furnish its own power is irrelevant. The expertise and investment needed to build a power plant, coupled with economies of scale, would deter many individuals from producing power for themselves rather than simply purchasing it. The legislature determined that the protection of the public interest required only limiting competition in the sale of electric service, not a prohibition against self-generation.

We approve the decision of the Public Service Commission.

It is so ordered.

EHRLICH, C.J., and OVERTON, SHAW, BARKETT and KOGAN, JJ., concur.

McDONALD, J., dissents with an opinion.

McDONALD, Justice, dissenting.

I dissent. In doing so, I accept the argument of PW Ventures, Inc. as set forth in its brief where it urges:

The cornerstone of "public utility" status and Commission jurisdiction under Chapter 366 is the provision of electric service "to the public". This phrase is not defined in Chapter 366, nor in any of the Commission's other jurisdictional statutes. Under Florida's rules of statutory construction, the phrase "to the public" must therefore be given either its plain and ordinary meaning or, if it is a legal term of art, its legal meaning.*City of Tampa v. Thatcher Glass Corporation,* 445 So.2d 578 (Fla. 1984); *Citizens v. Florida Public Service Commission,* 425 So.2d 534 (Fla. 1982); *Tatzel v. State,* 356 So.2d 787 (Fla. 1978); *Ocasio v. Bureau of Crimes Compensation,* 408 So.2d 751 (Fla. 3d DCA 1982). Under either test, a sale to a single industrial host in the circumstances of this case is not a sale "to the public."

* * * * * *

The phrase "to the public" commonly connotes the people as a whole, or at least a group of people. Webster's Ninth New Collegiate Dictionary (1983) gives two relevant definitions for "public":

2: the people as a whole: POPULACE

3: a group of people having common interests or characteristics: *specif:*the group at which a particular activity or enterprise aims

Black's Law Dictionary (Revised 4th ed.) similarly defines "public" to mean:

The whole body politic, or the aggregate of the citizens of a state, district, or municipality.... In one sense, everybody; and accordingly the body of the people at large; the community at large, without reference to the geographical limits of any corporation like a city, town, or county; the people. In another sense the word does not mean all the people, nor most of the people, nor very many of the people of a place, but so many as contradistinguishes them from a few.

Thus if Section 366.02(1) is given its plain and ordinary meaning, a person is not supplying electricity "to the public," if it supplies electricity only to a single 285*285 industrial customer on whose property the electric generating facility is located.

[1] PW Ventures is a Florida corporation which was originally owned by FPL Energy Services, Inc. (a wholly owned subsidiary of FPL Group, Inc.) and Impell Corporation (a wholly owned subsidiary of Combustion Engineering, Inc.). After the entry of the PSC order, FPL Energy Services, Inc. transferred its 50% interest to Combustion Engineering, Inc.

[2] Cogeneration involves the use of steam power to produce electricity, with some of the energy from the steam being recaptured for further use. The PSC seeks only to regulate the sale of electrical power.

[3] The power would be used by Pratt and several affiliated corporate entities and by the Federal Aircraft Credit Union which is also located on the property.

[4] While the PSC reminds us that the power generated by the project will actually be passed on to several entities, we prefer to address the issue in the context argued by PW Ventures.

[5] Initially, Florida Power and Light had an interest in PW Ventures and would, in effect, transfer its own client to a subsidiary. FP & L is not now involved. Yet, if the argument of PW Ventures is accepted, there might be nothing to prevent one utility company from forming a subsidiary and raiding large industrial clients within areas served by another utility.

[6] The holding of that case actually supports the PSC's alternative position that PW Ventures will actually serve several customers at the Pratt facility.

Tab 4

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Diffusion of environmentally-friendly energy technologies: buy versus lease differences in residential PV markets

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Abstract
Diffusion of microgeneration technologies, particularly rooftop photovoltaic (PV), represents a key option in reducing emissions in the residential sector. We use a uniquely rich dataset from the burgeoning residential PV market in Texas to study the nature of the consumer's decision-making process in the adoption of these technologies. In particular, focusing on the financial metrics and the information decision-makers use to base their decisions upon, we study how the leasing and buying models affect individual choices and, thereby, the adoption of capital-intensive energy technologies. Overall, our findings suggest that the leasing model more effectively addresses consumers' informational requirements and that, contrary to some other studies, buyers and lessees of PV do not necessarily differ significantly along socio-demographic variables. Instead, we find that the leasing model has opened up the residential PV market to a new, and potentially very large, consumer segment—those with a tight cash-flow situation.

Keywords: residential solar PV, discount rates, solar business models, individual decision-making

S Online supplementary data available from stacks.iop.org/ERL/8/014022/mmedia

1. Introduction

Two questions prompted the work in this paper. First, what can be learned from the diffusion of solar photovoltaics (PV) for improving existing solar programs and the design of others in newer markets? As policy support for these technologies is waning, this increases the pressure for incentive programs to become more efficient (US DOE 2008, 2012). Second, what lessons can the residential PV market shed on the individual decision-making process? The scale of capital investment for solar PV is quite high relative to most other household investments. So, presumably, the choice to adopt PV forces individuals to consider the (alternative) options more carefully than most investment decisions (Jager 2006). Unpacking the decision to adopt PV, then, might provide insights into the nature of the individual decision-making process.

Understanding the nature of the decision-making process has important practical implications for the design of mechanisms that incentivize reduction of greenhouse gas (GHG) emissions from energy use. With 22.2% consumption of primary energy and 21.4% of the total GHG emissions (EIA 2010) the residential sector is a key target for reducing energy demand and GHG emissions. Diffusion of microgeneration technologies, particularly rooftop PV, represents a key option in meeting demand and emissions reductions in the residential sector (US DOE 2012). As different actors have tried to design programs and incentives to spread the adoption of more efficient and environmentally-friendly consumption and generation devices (Taylor 2008), the nature of the individual's decision-making process has come to sharper focus (Allcott and Mullainathan 2010, Dietz 2010, Drury *et al* 2011, Jager 2006, Keirstead 2007, Bollinger and Gillingham 2012). Therefore, the last few years of experience with

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residential PV provides an early and unique opportunity to refine our understanding of how individual decision-making impacts technology diffusion.

Three lines of theory are relevant to this work. First, decision-making at the individual level. While the neoclassical microeconomic theory presumes that individual decision-makers are rational and information-prescient, there is increasing evidence that individual decision-makers depart significantly from the neoclassical model (Camerer *et al* 2004, Frederick *et al* 2002, Gintis 2000, Todd and Gigerenzer 2003, Wilson and Dowlatabadi 2007).

Second, empirical evidence of the use of high discount rates for future returns from energy-saving technologies (Gately 1980, Hausman 1979, Meier and Whittier 1983, Ruderman *et al* 1987). Expectations of rapid technological change, information barriers, and other non-monetary costs are some of the factors that give rise to the use of high implicit discount rates (Hassett and Metcalft 1993, Howarth and Sanstad 1995). In general, this phenomenon discourages the adoption of technologies whose benefits are spread over a long time horizon. The use of upfront capital subsidies have been proposed as a way to overcome this adoption barrier (Guidolin and Mortarino 2009, Hart 2010, Jager 2006, Johnson *et al* 2012, Timilsina *et al* 2011).

Third, business models for accelerating the deployment of technologies by addressing market barriers (Gallagher and Muehlegger 2011, Margolis and Zuboy 2006, Sidiras and Koukios 2004) facing individual decision makers—in particular the leasing model. Several researchers suggest that the option to lease a technology effectively addresses the high discount rate problem (Coughlin and Cory 2009, Drury *et al* 2011)—as well as some of the information failures associated with new technologies (Faiers and Neame 2006, Shih and Chou 2011).

2. Data

Our analysis uses a new household-level dataset built through two complementary data streams: (i) a survey of residents who have adopted PV and (ii) program data for the *same* adopters obtained from utilities that administer PV rebate programs. The survey, among other factors, explores *why* PV adopters made the financial choices they did (say, buy versus lease), and their own assessment of the attractiveness of their investment (Rai and McAndrews 2012). The survey was administered electronically in Texas during August–November 2011 and received 365 responses from the 922 PV owners contacted.

All survey respondents reported residing in areas of retail electricity choice in Texas (see supplementary information for spatial distribution available at stacks.iop.org/ERL/8/014022/mmedia). The mean size of the PV system installed was 5.85 kW-DC and the average age of respondents was 52 yr old. The mean household income was between \$85 000 and \$149 999 and 84.9% reported that at least one member of the household had achieved a college degree or higher level of education. Each of the prior demographics is significantly different from state-wide averages. That is, the survey population was wealthier, older, and better-educated than the average Texas resident. No significant difference was found between lessees and buyers of PV on any demographic variable.

Of the 365 responses, we matched complementary program data for 210 respondents. The program data provides several data points, including (i) installed cost of the system, (ii) price and structure of lease payments if the system was leased, (iii) system capacity (kW, DC and AC), (iv) amount of rebates disbursed, (v) aggregate household electricity consumption from the prior year, (vi) retail electricity provider (REP), electric plan, and marginal cost of electricity consumption just prior to PV installation, and (vii) projected annual electricity generated by the system based on orientation, derating factor, and geography.

3. Methodology

Our strategy is to compare the financial metrics that PV adopters used to evaluate their investment decision (*reported metrics)* obtained through survey (above) with an 'objective' assessment of those same metrics (*modeled metrics*). To enable the comparison, we built a financial model that calculates the expected lifecycle costs and revenues of PV system ownership for the residential buying and leasing business models (NREL 2009, Kollins *et al* 2010). Our model is distinct in two ways. First, our uniquely comprehensive dataset allows detailed cost and revenue calculations for *each* respondent (decision maker). Second, it includes detailed features of *household-level* electricity consumption, electricity rates, and PV-based electricity generation, including time-of-day and monthly variations. Next, we provide an overview of our methodology; however a more thorough description is provided in the supplemental information.

3.1. Cash-flow model

For each PV adopter we calculate a series of monthly expected costs (C_k) and revenues (R_k) accrued over the lifetime of the PV system, where k is the number of months since the PV system was installed. Therefore, cash flows (CF_k) of the investment are:

$$\mathrm{CF}_k = R_k - C_k. \tag{1}$$

Using these cash flows we calculate the net present value (NPV) using a 10% annual discount rate, NPV per DC-kW, payback period for each household's investment, and estimate each individual's implicit discount rate.

3.2. System costs

Costs (C_k) have three monthly components: (a) system payments (C_{system_k})—either lease payments or loan payments when financed and a down payment as appropriate, (b) operations and maintenance costs ($C_{\mathrm{O\&M}_k}$), and (c) cost of inverter replacement (C_{Inverter_k}) where:

$$C_k = C_{\mathrm{system}_k} + C_{\mathrm{O\&M}_k} + C_{\mathrm{Inverter}_k}. \tag{2}$$

System payments for *buyers* comprise a down payment in the first period and loan payments if the system was financed. The net system cost is the installed cost less the utility rebate reported in the program data less applicable federal tax credits. We assume that: (i) buyers will make periodic operation and maintenance-related (O & M) expenses equivalent to 0–0.75% yr^{-1} of the system's installed cost; these O&M costs are expensed equally each month, and (ii) inverters require replacement after 15 yr of use and cost \$0.7–0.95 per DC-Watt. In section 3.4 we present a set of scenarios that systematically vary these parameters.

Lessees are not obligated to pay O&M or inverter replacement costs as this is a value-adding service provided by the lessor (Mont 2004). Therefore, the only costs of ownership incurred are lease payments (upfront payment and monthly lease payments). Within the sample, 69% of lessees paid for their lease entirely through a 'prepaid' down payment, 26% through only monthly payments, and 4% through a combination of monthly payments and a down payment. For all leased systems analyzed, we use the actual lease payments being made by the lessees.

3.3. System revenue

PV systems generate value by reducing owners' electricity-bill expenses during the life of the system. Therefore, the difference between electric bills the owner would have incurred without the system (BAU bill) and those with the PV system (PV bill) is effectively a monthly stream of revenues (R_k). The value of these revenues depends on the structure and rates of both bills. Our model forecasts these revenues over the system's lifetime.

3.3.1. Electricity consumption and generation profiles. Two central factors in the PV value proposition are seasonal and hourly variations in the system's generation and the household's consumption of electricity. For both factors, we use each respondent's historic annual consumption and expected annual system production (kWh) as reported in the program data, but not individual consumption or generation patterns. To simulate these hourly and seasonal variations we used load profiles published by the Electricity Reliability Council of Texas (ERCOT) of average residential consumption patterns in north-central Texas in 2010 (ERCOT 2010) and a PV generation profile for the Dallas-Ft. Worth area taken from the PVWATTS model created by the US National Renewable Energy Laboratory (NREL 2011).

Furthermore, we assume that patterns and quantities of electricity consumption are invariant over the lifetime of the PV system. This is not a robust assumption per se, since we do not capture household-level patterns of consumption that differ from the ERCOT profile or that evolve over time. But, since the goal is to *compare* the objective and reported financial metrics, this assumption is robust enough for our analysis because any variations in consumption profiles will largely cancel out in the revenue calculations.

3.3.2. Electricity rates. Within the ERCOT deregulated electricity market customers freely choose retail electricity service among providers with varying rates and bill structures (TECEP 2012). An important factor is whether their Retail Electricity Provider (REP) offers a plan that credits any moment-to-moment excesses of PV generation over consumption outflowed to the grid (Darghouth *et al* 2011, Mills *et al* 2008). Unlike many retail choice states, the ERCOT market does not mandate that REPs provide credits for these 'outflows' (PUCT 2012). Current practice is for REPs to credit outflows at a rate below the marginal price of electricity.

While it is tempting to assume that consumers will select electricity plans which offer the highest value for their PV system, it is not obvious what depth of information finding and analysis decision-makers go through to determine which REP provides this greatest value (Conlisk 1996, Fuchs and Arentsen 2002, Gigerenzer and Todd 1999, Goett *et al* 2000, Roe *et al* 2001, Tversky and Kahneman 1974). We account for this dilemma through a set of scenarios, discussed next.

3.4. Scenarios

To account for uncertainty in the model's parameters (Bergmann *et al* 2006, Laitner *et al* 2003), calculations are structured as a series of five scenarios—*Very Conservative, Conservative, Baseline, Optimistic, and Very Optimistic* (table 1). Scenarios employ progressively more optimistic assumptions that increase the value of solar to the consumer. Parameters varied were: (i) the annual growth rate in nominal retail electricity price (0–5%) (ii) if bought, lifetime of the system (20 or 25 yr) (iii) system loss rate (0.75–0.25% yr^{-1}) (iii) O&M costs as a percentage of installed costs incurred per year (0.5–0% yr^{-1}), and (iv) inverter replacement cost (\$0.95 W^{-1}–\$0 W^{-1}). Note that these scenarios are not intended to represent likely or unlikely outcomes, but to explore how consumers' differing assumptions would affect their evaluation of PV's value.

Scenarios also vary the customer's retail electricity plan *post-installation*. The most conservative scenario (scenario 1) assumes that consumers remain on their pre-PV plan for the lifetime of the system, whereas the most optimistic scenario (scenarios 4 and 5) assumes that the consumer actively researches and selects plans that minimize their electricity bill. The baseline scenario (scenario 3) assumes that consumers will adopt a 'solar' plan if offered by their REP, but will not transfer REPs. In addition, the consumer is credited 7.5 ¢ kWh^{-1} for outflows if their current REP does not offer a solar plan—since we believe that nearly all REPs will offer an outflow credit in the future. Indeed, most major REPs do so already.

4. Results

We present here the results of our analysis. Framing this analysis are the differences between buying and leasing consumers. Contrary to Drury *et al* (2011), we found no statistically significant differences between the two groups on demographic factors including income, age, education, and race as well as contextual factors such as the size of their system, annual electricity consumed, or electricity rates. Based on these results and those that follow, our conclusion is that at this stage in the diffusion of residential PV buyers and leasers *do not* represent different demographic groups, but rather *different consumer segments* within the residential PV market.

Table 1. Description of the scenarios.

Scenario	(1) V. Conservative	(2) Conservative	(3) Baseline	(4) Optimistic	(5) V. Optimistic
Elec. cost growth	0.0% yr^{-1}	2.6% yr^{-1}	2.6% yr^{-1}	3.3% yr^{-1}	5.0% yr^{-1}
System life	20 yr	20 yr	25 yr	25 yr	25 yr
System loss rate	0.75% yr^{-1}	0.5% yr^{-1}	0.5% yr^{-1}	0.5% yr^{-1}	0.25% yr^{-1}
Maintenance costs	0.5% yr^{-1}	0.25%	0.25% yr^{-1}	0.15% yr^{-1}	0% yr^{-1}
Inv. replace. cost	\$0.95 W^{-1}	\$0.95 W^{-1}	\$0.7 W^{-1}	\$0.7 W^{-1}	None
Electricity plan after PV adoption	Keeps same REP and plan post-installation; no outflows	Adopts solar plan if offered by current REP	Adopts solar plan if offered by current REP; min. 7.5 ¢ kWh^{-1} outflow	Adopts plan with max. value among current market solar plans or BAU plan	Same as scenario 4

4.1. Installed cost and cost of ownership

Installed costs (\$$W^{-1}$) of leased systems (Mean = 8.3, Std. dev. = 0.53) were significantly more than those of bough systems (Mean = 6.2, Std. dev. = 1.4) and the mean differences were highly significant ($t(201) = 16.08$; $p < 0.001$). This corroborates similar installed cost differences for bought and leased systems nationally (Barbose *et al* 2012). As discussed in section 3.2, recall that while buyers' cost of ownership is the installed cost less applicable rebates, the installed cost is generally *not* reflective of the lessees' cost of ownership, which are only their lease payments. Surprisingly, the mean lessees' cost of ownership (\$0.70 W^{-1}) were substantially less than those of buyers (\$2.64 W^{-1})[4]. Accordingly, we found that lessees had a statistically significant greater NPV per capacity ratio (NPV/DC-kW) than buyers in all but scenario 5 (figure 1; only baseline scenario shown).

How is it possible that leased systems are installed at higher costs than bought systems, but that lessees face a lower cost of ownership than the equivalent bought system? As others have noted (for example see, Barbose *et al* 2012), the installed cost reported to state and utility PV incentive programs is often the 'fair market value', or the appraised value, reported when applying for the 1603 Treasury Cash Grant or Federal ITC. Since the benefits of both the 1603 Treasury Cash Grant and tax benefits from MACRS increase with the appraised value of the system, it is plausible that some leasing companies might be inflating the appraised value—at least the incentive to do so clearly exists. Indeed the SEC and IRS recently began an investigation of several leading leasing firms to determine if the true fair market value of installed PV systems were materially lower than what the firms had historically claimed (SEC 2012). If proven true, one implication of this financial strategy would be that since additional system costs and company profits are recouped through the tax structure, leasing companies adopting such strategies would be able to offer lower rates to their customers

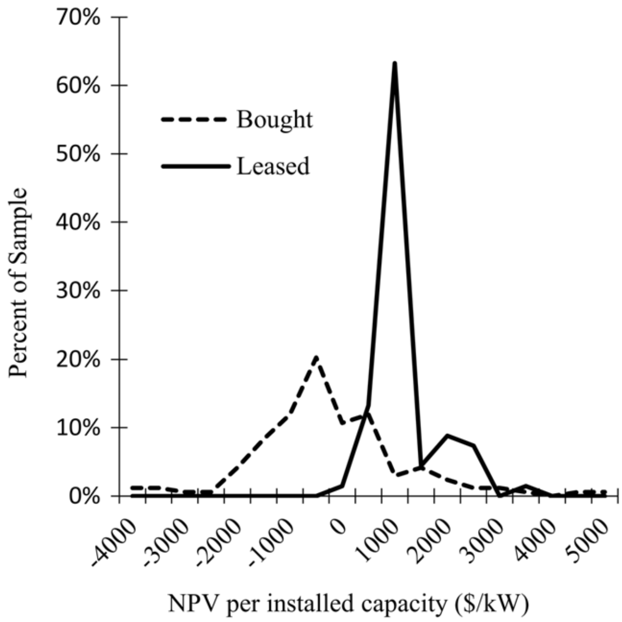

Figure 1. Distribution of modeled NPV kW^{-1} assuming *baseline* model parameters.

(the lessees). The fact that we indeed find the cost of leasing PV systems (by the lessees) to be much lower than the cost of buying PV systems lends some support to the hypothesis that some leasing companies might be employing such financial strategies.

Therefore, we tentatively explain lower lessees' costs of ownership through the following mechanisms: (i) maximization of federal tax benefits by leasing companies (lessors) through the financial strategy described above; (ii) in the current policy environment, lessors are able to access additional financial incentives that buyers cannot access, particularly, accelerated depreciation (Bolinger 2009, Coughlin and Cory 2009); (iii) economies of scale present in the operation of a larger fleet of leased systems; (iv) ability for lessors to raise capital at a lower cost, which would increase their leveraged return on capital; and (v) since the lease contracts are typically only 15–20 yr as compared to the generally reported lifetime of PV panels of 20–25 yr, leased systems will likely have some residual value; in theory, the lessors could recoup the residual value at a later date, which

[4] Note that the upfront cost of ownership does not reflect the operational life of PV systems or their performance over that lifetime. In general, most analyses assume an operational life for PV systems of 20–25 yr, which is applicable to buyers of PV systems. Lease contracts typically terminate after 15–20 yr. So the difference in the upfront cost of ownership of bought versus leased systems should be put in this context. However, as discussed below, NPV calculations incorporate this difference in the length of cash flows.

would allow them to offer the leased systems at lower rates today. All of these mechanism would lower costs faced by lessors, and therefore reduce the size of the lease payments required to achieve a given rate of return. In a competitive leasing market, then, these mechanisms would translate into lower costs faced by lessees—just as we find. A deeper explanation of these aspects would require financial analysis of the leasing companies' balance sheets, which is beyond the scope of this paper.

If leasing is financially more attractive, why don't more adopters choose to lease? For many the option did not exist—73% of buyers reported not having the option to lease when making their decision. There is also evidence in the literature of conspicuous consumption for novel 'green' technologies (Dastrop *et al* 2011, Sexton 2011); under this paradigm, consumers could derive additional utility from the status gained by owning, rather than leasing, their system. Residence uncertainty was not a factor, as each group reported a similar (10–15 yr) period that they expected to continue living in their homes. Finally, a majority of PV adopters who had the option to either buy or lease a PV system, but chose to buy report concerns about potential difficulties with the leasing contract as a factor in their decision to buy[5]. Considering all these factors, we conclude that buyers who did have the option to lease, but chose to buy, had adequate cash-flow such that they preferred the contractually simple buying option, even though the leasing option is nominally cheaper.

4.2. Payback period comparison

Consistent with previous research (Camerer *et al* 2004, Kempton and Montgomery 1982, Kirchler *et al* 2008), the majority of respondents (66%) reported using payback period to evaluate the financial attractiveness of their investment as opposed to NPV (7%), internal rate of return (27%), net monthly savings (25%), or other metrics (6%). 10% made no estimate of the financial attractiveness. Respondents also reported the values of the metrics they used. These responses allow us to compare reported metric values (*reported*) to the values individually generated from the financial model (*modeled*) (figure 2; only baseline scenario shown).

For buyers, scenario 4 minimized the average absolute difference between reported and modeled payback period ($M = 2.6$ yr, $SD = 2.4$), followed by scenario 5 ($M = 3.1, SD = 1.9$). For lessees, scenario 3 ($M = 1.1, SD = 0.7$) was the best fit, followed by scenario 2 ($M = 1.296, SD = 0.704$). Scenario 1 was a poor fit overall. This suggests that buyers assumed parameters similar to those of scenario 4 when evaluating their investment. That is, buyers were optimistic when assessing the likely revenues and costs associated with their investment decision. By the same argument, lessees were more realistic and precise when making their investment decision. This is consistent with the fact that lessees receive much of this financial information from leasing companies, who use very detailed and sophisticated financial models.

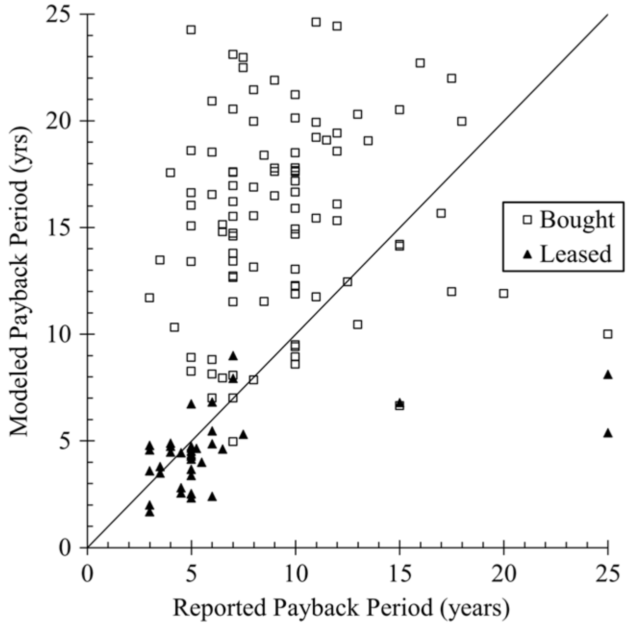

Figure 2. Comparison of reported and modeled payback period in scenario 3. Mean difference between modeled and consumer payback period: buyers = 7.1 yr^{-1}; leasers = 1.1 yr.

4.3. Implied discount rate

For all calculations of NPV reported above a 10% annual discount rate was assumed. In this section we present discount rates calculated separately for each individual respondent. Specifically, we first determine each respondent's *implied NPV* and then back-calculate their discount rate using the implied NPV and their modeled cash flows. To determine the implied NPV, respondents were asked on a 5-point Likert-scale how strongly they agreed with the following five statements: (i) 'I would not have installed the PV system if it had cost me $**1000** more'…(v) 'I would not have installed the PV system if it had cost me $**5000** more'. One expects respondents to increasingly *agree* that they would *not* have installed the PV system as the price increased. The above question estimates the respondent's implied NPV by extrapolating how much more the respondent would have paid before becoming indifferent to purchasing the system or forgoing the investment (figure 3).

Of the 210 respondents in our dataset, 92 responses were excluded from these calculations—69 whose implied NPV was outside the range tested ($0–$5000), 7 responses which implied an increasing willingness to pay, and 16 non-responses. Of the excluded respondents, 55 respondents indicated they would have been willing to pay at least $5000 more for their system—of which 76% were buyers and 24% leasers. That is, a significant per cent of the sample (26.2%) did assign a positive value to their investment, yet were not captured within this calculation because of insufficient data.

[5] There were 44 respondents in our sample who had the option to either lease or buy a PV system, but chose to buy. Of those 24 responded to a 5-point Likert-scale question on how strongly they agreed with the statement, 'I was concerned about potential difficulties related to the leasing contract'. 50% agreed or strongly agreed with the statement, while only 8.5% disagreed or strongly disagreed with the statement.

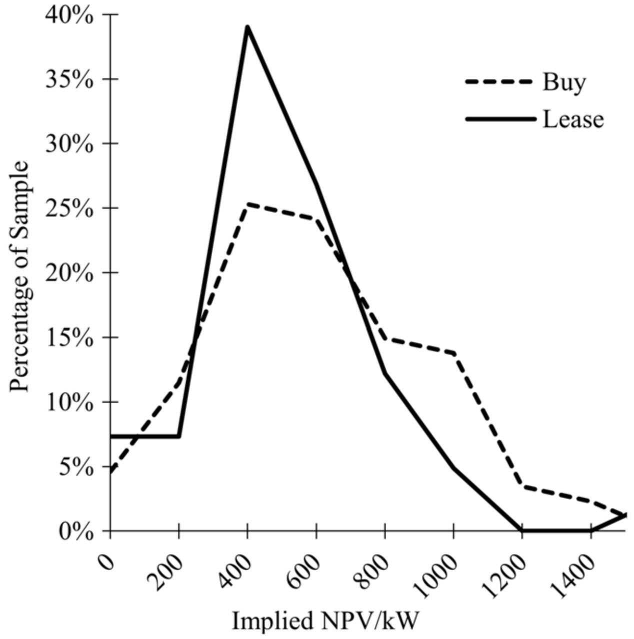

Figure 3. Distribution of implied NPV kW^{-1} for buyers and leasers; difference of mean is not significantly different than zero.

In the end, there are 81 buyers and 37 lessees remaining for the discount rate analysis reported in this section.

Using the implied NPV, we solve for the monthly discount rate (r_m), required to equate the respondent's implied NPV with the cash flows modeled earlier.:

$$\mathrm{NPV}_{\mathrm{implied}} = \sum \mathrm{CF}_k = \sum \frac{[R_k - C_k]}{(1 + r_m)^k}. \quad (3)$$

The monthly discount rate is then annualized using (4):

$$r = (1 + r_m)^{12} - 1. \quad (4)$$

Thus, r represents each respondent's discount rate implied by their willingness to pay and their modeled cash flows. As the cash flows vary with each scenario, implied discount rates also vary with scenarios.

Using baseline (scenario 3) parameters, the mean discount rate for buyers was $7 \pm 5\%$ and for lessees was $21 \pm 14\%$ ($\pm 1\sigma$) (tables 2 and 3). The calculated implied discount rates are higher in the optimistic scenarios since cash flows increase as the scenarios become more optimistic. Across all scenarios and income levels lessees' implied discount rates are significantly higher than buyers by 8–21%.

It is important to note a similarity in the timing of leased and bought payments—the majority (69%) of lessee respondents chose to structure their leases as a single 'prepaid' down payment, which is similar to the financial structure of a bought system, but significantly smaller in the scale of investment. After taking all incentives into account, for lessees the upfront payment is on the order of \$4000 and for buyers it is \$15 000 for a 6 kW-DC system. Yet, each group expects to receive a similar (normalized) NPV for their investment. That is possible only when these groups have differing cash urgencies. Indeed, in open-ended survey questions, 66.2% of lessees agreed or strongly agreed that tight cash availability was one of the key factors in their decision to lease, whereas buyers generally did not have this problem. Given that there are little, if any, demographic differences between buyers and lessees, then, we infer that at this stage in the residential PV market buyers and lessees represent *different consumer segments* within a similar socio-demographic makeup. Put differently, compared to the average buyer the average lessee is not lower income *per se*—the majority of the lessees have some cash availability, just not enough to outright buy their PV system.

In general, our point is that within populations with similar demographics it is possible that there are variations in disposable income, and those variations are a key factor in ownership model choices[6]. Consistent with a large body of work in the diffusion of innovations tradition (Rogers 2003), our results suggest that there is a hierarchy within the population regarding the adoption of technologies. In early stages of technology diffusion, as is the case with PV now, information (awareness of products, interest in energy, etc) is the precursor, which is more likely to be found in higher income, more educated segments of the population. Within those segments, those with tighter cash flows opt for leasing, if that option is available. Thus, the leasing model appears to be especially effective in the early stages of a technology's diffusion, as it unlocks the cash-strapped but information-aware segments of the market. Put differently, the leasing model accelerates the early adoption stage of a technology's diffusion, thereby quickly establishing a wider base on which later adoption can build upon.

4.3.1. Discount rate and income. Previous literature starting with Hausman (1979) suggests that an inverse relationship exists between household income and consumer discount rate. That is, poorer consumers have more urgent needs for their cash than wealthy ones. At higher incomes, where one has a greater degree of spare income, the rate of return of investments (and hence, their discount rate) should converge to market returns. Our results are mixed in regard to these earlier findings.

A one-tailed t-test comparing the difference in mean discount rate among income groups for the baseline scenario was performed using the hypotheses H_o: $\mathrm{DR}_1 = \mathrm{DR}_2$, H_a: $\mathrm{DR}_1 \geq \mathrm{DR}_2$, and H_o: $\mathrm{DR}_2 = \mathrm{DR}_3$, H_a: $\mathrm{DR}_2 \geq \mathrm{DR}_3$, where DR_1 is the mean implied discount rate for income group 1 and so on[7]. This test was performed for both income pairs ($\mathrm{DR}_1 \geq \mathrm{DR}_2$, $\mathrm{DR}_2 \geq \mathrm{DR}_3$) since we expect the implied discount rate to monotonically decrease with income.

Even with a 90% confidence interval, we did not find a statistically significant relationship between income and discount rate for either buyers or lessees. We explain this discrepancy with two reasons. First, small sample size, particularly in the leasing sample, reduced our test's statistical

[6] We note, however, there are several factors besides cash availability that can guide ownership choices—priority of environmental value over financial concerns, intended length of residence, financial security, and so on.

[7] Income groups were: income 1: \$0–\$84 999 year^{-1}; income 2: \$85 000–\$149 999 year^{-1}; income 3:\$150 000 + year^{-1}.

Table 2. Mean implied discount rate for buyers along income and scenarios with $\pm 1\sigma$.

Buyers	All incomes	\$0–\$85k	\$85k–\$150k	\$150k+
N	**81**	22	37	22
Scen 2: conservative	**6%** $\pm$ **6%**	6% $\pm$ 5%	6% $\pm$ 8%	7% $\pm$ 6%
Scen 3: baseline	**7%** $\pm$ **5%**	7% $\pm$ 4%	6% $\pm$ 6%	7% $\pm$ 6%
Scen 4: optimistic	**13%** $\pm$ **6%**	12% $\pm$ 5%	13% $\pm$ 6%	13% $\pm$ 7%
Scen 5: V. Optimistic	**18%** $\pm$ **7%**	17% $\pm$ 5%	18% $\pm$ 7%	17% $\pm$ 8%

Table 3. Mean implied discount rate for leasers along income and scenarios with $\pm 1\sigma$.

Leasers	All incomes	\$0–\$85k	\$85k–\$150k	\$150k+
N	**37**	13	13	11
Scen 2: conservative	**20%** $\pm$ **15%**	22% $\pm$ 19%	20% $\pm$ 14%	18% $\pm$ 12%
Scen 3: baseline	**21%** $\pm$ **14%**	23% $\pm$ 18%	22% $\pm$ 13%	19% $\pm$ 12%
Scen 4: optimistic	**32%** $\pm$ **17%**	33% $\pm$ 22%	35% $\pm$ 15%	30% $\pm$ 14%
Scen 5: V. Optimistic	**35%** $\pm$ **13%**	29% $\pm$ 9%	38% $\pm$ 13%	36% $\pm$ 16%

power. Second, both groups exhibit characteristics typical of early adopters—wealthier, more educated, etc. These characteristics could negate the relationship between income and discount rate for products in settled markets as early adopters typically derive additional utility from adopting new technologies beyond financial benefits (Faiers *et al* 2007, Labay and Kinnear 1981, Rogers 2003). In agreement with previous literature, we do find that discount rates for buyers in the conservative, baseline, and optimistic scenarios (scenarios 2–4) ranges between 7 and 13%, which is close to market returns. This also supports our finding that buyers of PV systems are in a relatively comfortable cash-flow position.

5. Conclusion

We have studied the economics of the decision-process of individual consumers, particularly their decision to buy or lease a residential PV system. Consistent with several other studies, we find that a majority of PV adopters used payback period—not net present value (NPV)—as the decision-making criterion. We also find that owing to the peculiarities of financing and incentive mechanisms, the pre-rebate installed costs of leased PV systems are significantly higher than the bought systems, yet lessees end up paying nominally much lower amounts than buyers of PV. We calculate individual-level discount rates across a range of scenarios, finding that buyers employ discount rates 8–21% lower than lessees. Those who lease typically have a tighter cash-flow situation, which, in addition to less uncertainty about technological performance, are the main reasons for them to lease. As we do not find any significant variation between buyers and lessees on any socio-demographic dimension (income, age, etc) this suggests that the leasing model is making PV adoption possible for a new consumer segment—those with a tight cash-flow situation. As the diffusion of PV spreads to lower-income households, who generally experience tighter cash-flow than wealthier households, this implies that, *ceteris paribus,* moving forward the leasing model will likely be the predominant form of PV adoption. From this perspective, the leasing model has opened a new market segment at existing prices and supply chain conditions—and represents a business model innovation.

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VALUE OF THE GRID TO DG CUSTOMERS

IEE Issue Brief
September 2013
Updated October 2013

IEE INNOVATION ELECTRICITY EFFICIENCY
An Institute of The Edison Foundation

Value of the Grid to DG Customers

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September 2013
Updated October 2013

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VALUE OF THE GRID TO DG CUSTOMERS

Some advocates of distributed generation (DG) claim that the DG customer derives no benefit from being connected to the host utility's distribution system.[1] While it is easy to say that a DG customer is "free from the grid," that is simply not true – even for a DG customer (or a micro-grid) that produces the exact amount of energy that it consumes in any given day or other time interval.[2]

This paper describes how a DG customer (or a micro grid) that is connected to the host utility's distribution system 24/7 utilizes grid services on a continuous, ongoing basis. The point is to recognize the value of these grid services and to develop a methodology for the DG customer to pay for using the services. The utility's cost of providing grid services consists of at least four components – the typical fixed costs associated with: (i) transmission, (ii) distribution, (iii) generation capacity, and (iv) the costs of ancillary and balancing services that the grid provides throughout the day for the DG customer.

There is a related question about how much DG customers should be paid, or credited, for the excess electric energy they produce on-site and inject into the grid. This paper does not explicitly address this "value of on-site energy" issue.

THE BENEFITS OF REMAINING CONNECTED TO THE DISTRIBUTION SYSTEM

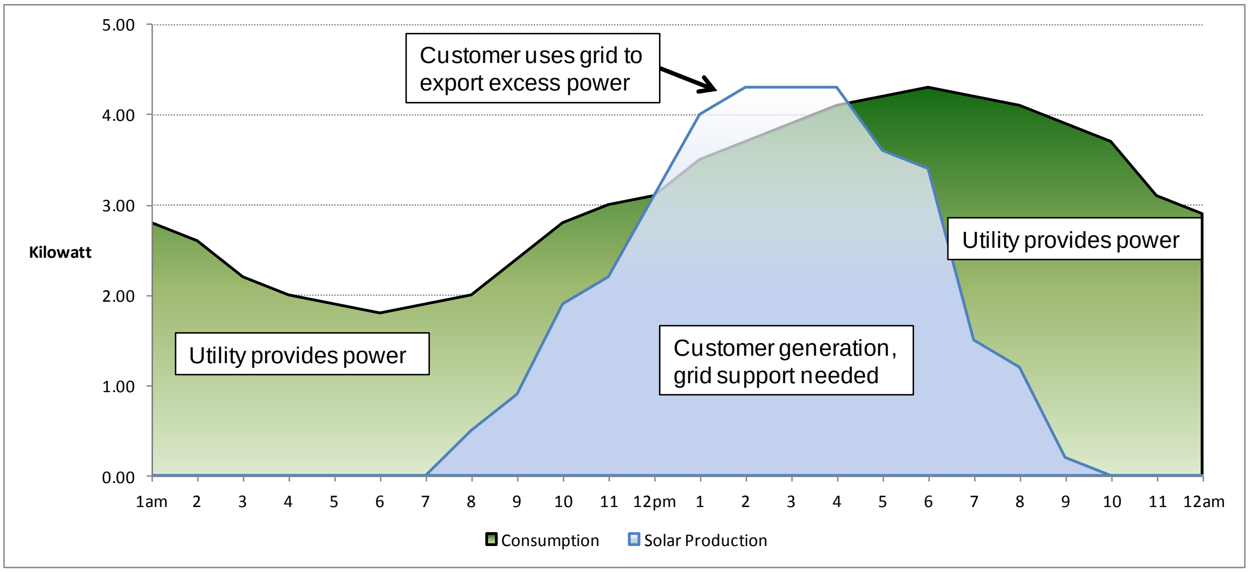
Consider a residential or small commercial customer with solar PV panels on its rooftop. Figure 1 displays a typical hourly pattern of energy production and consumption for such a customer. The green area is the energy delivered by the host utility and consumed by the customer. The area under the blue curve is the energy produced on-site by the solar panels. The area below the blue curve and above the green line is the excess energy injected into the utility's distribution system. The key take-away from this graphic is that the customer's consumption and generation are almost never equal; consequently, most of the time the customer is using the external power system to offset the difference between the customer's consumption of electric energy and its on-

1 A recent Forbes article, "Distributed Generation Grabs Power from Centralized Utilities," August 8, 2013, ignores and fails to mention the grid services that are provided to DG customers continuously by the host utility.

2 The term, DG, refers to small retail customers with on-site generation that are net metered.

site production. In most cases the customer will be taking energy from the grid during many hours of the day. For example, the customer depicted in Figure 1 takes power from the grid in all hours except from noon to about 4:30 pm.

Figure 1: Typical Energy Production and Consumption for a Small Customer with Solar PV



Customers with any type of DG that are connected to the grid will be utilizing external grid services to:

- balance supply and demand in sub-second intervals to maintain a stable frequency *(i.e.*, regulation service);
- resell energy during hours of excess generation and deliver energy during hours of deficit generation;
- provide the energy needed to serve the customer's total load during times when on-site generation is inoperable due to equipment maintenance, unexpected physical failure, or prolonged overcast conditions (*i.e.*, backup service);
- provide voltage and frequency control services and maintain high AC waveform quality.

Clearly, even if the customer's total energy production over some time interval (*e.g.*, a monthly billing cycle) exactly equals its consumption over that same interval, that customer is still utilizing at least some, if not all, of the above grid services during that time interval.

So what value does a customer with solar PV generation derive from remaining connected to the grid? Let's begin by examining the charges that a typical residential customer consuming an average of about 1000 kilowatt-hours (kWh) per month [average consumption based on Energy Information Administration (EIA) data and rounded] will pay for grid services, <u>excluding the charges for the electric energy itself</u>. These charges are designed to allocate to the customer its fair share of the fixed costs associated with the transmission system, the distribution system, balancing and ancillary services, and the utility's (or the retail supplier's) investment in generation capacity.[3] As stated earlier, the electric energy charges designed to recover the cost of the energy (kWh) consumed by the customer (including the associated transmission and distribution losses), are excluded here. Table 1 illustrates these charges for a typical residential customer.[4]

Table 1 – Non-Energy Charges Paid by a Typical Residential Customer on a Retail Tariff

Average Residential Customer: Non-Energy Charges as Percent of Typical Monthly Bill	
Average Monthly Usage (kWh)*	1000
Average Monthly Bill ($)*	$110
Typical Monthly Fixed Charges	
Ancillary/Balancing Services	$1
Transmission Systems	$10
Distribution Services	$30
Generation Capacity ^	$19
Total Fixed Charges for Customer	$60
Fixed Charges as Percent of Monthly Bill	**55%**

*Based on Energy Information Administration (EIA) data, 2011
^The charge for capacity varies depending upon location. This is just an estimate.

In this example, the typical residential customer consumes, on average, about 1000 kWh per month and pays an average monthly bill of about $110 (based on EIA data). About half of that bill (*i.e.,* $60 per month) covers charges related to the non-energy services provided by the grid,

3 In "retail choice" states the retail customer can choose its energy supplier, which may not be the utility. In all other states the utility will be the retail supplier.

4 Other charges, such as sales and franchise taxes and environmental charges could be added to the table; however, the focus of this paper is on the grid services that are provided by the host utility.

including a charge for generation capacity. Because residential retail rates are almost always designed to recover most of the power system's fixed costs through kWh charges, a DG customer will avoid paying some or all of its fair share of the fixed costs of grid services. Ultimately the fixed costs that the DG customer does not pay, which are significant, will be shifted to other retail customers. In this example, each DG customer shifts up to $720 per year in costs (*i.e.,* $60 * 12 months) to other retail non-DG customers. To put this into context, if 50 percent of the residential customers in a given utility service territory had DG, the non-DG residential customers in that service territory could experience bill increases of up to 55 percent – from $110 per month to $170 per month. Clearly this cost shift is substantial and simply not fair.

IEE submits that DG customers should pay their fair share of the cost of the grid because pushing any of this cost onto non-DG customers raises serious economic efficiency and fairness issues. Indeed this is one of the key issues in the current debate over net metering.

To illustrate the value provided by the grid for a solar PV customer, consider what it would cost that customer to self-provide the technical equivalent of these services through some combination of energy storage and/or thermal generation (*e.g.,* a Generac home generator).

Preliminary estimates of the monthly costs that a typical residential customer would have to incur to self-provide the balancing and backup services that the grid currently provides are substantially higher than the $60 charge shown in Table 1.[5] Furthermore, this cost estimate of self-provision excludes the additional cost of maintaining the level of voltage and frequency control and AC waveform quality currently provided by the grid. An off-the-grid DG customer (or micro-grid) simply cannot provide, at reasonable cost, the same quality of service that a large power system provides. So, in fact, most DG customers remain connected to the grid today and utilize grid services.

This straightforward cost comparison to "self providing" grid services reveals three things. First, the balancing and backup services that the grid provides to DG customers are needed and have substantial value. Second, it does not make economic sense for a DG customer to self-provide these services. Third, it is unfair for DG customers to avoid paying for these grid services,

5 The Electric Power Research Institute (EPRI) is developing estimates of the cost of self-providing grid services and expects to release its results in 2014.

thereby shifting the cost burden to non-DG customers. Obviously, DG customers should pay their fair share of the cost of the grid services that the host utility provides.

Economies of Scale Associated with Power Systems

In many ways, the growth of DG and micro grids today goes full circle back to the early days of the electric power industry. Initially power systems were isolated and each served its own service area. As service areas expanded, utilities began to interconnect. PJM was the first entity to interconnect utilities for reliability purposes and to centrally provide balancing services. This evolution was driven by the substantial economies of scale that still exist today as ISO/RTO markets continue to grow and expand.[6]

These interconnection entities developed for good reasons. When a small power system interconnects with a larger one, all members of the resulting combined entity benefit. However, it has been observed that the small system benefits disproportionately more than the incumbent members. For example, the small system's operating reserve margin will decrease substantially. This phenomenon is even more pronounced when a micro-grid interconnects with a power system.

DG Market is Growing, Pricing it Right is Key

Although net metering was a convenient vehicle for kick-starting the DG market, there are now serious questions among state policymakers regarding its continuation and needed reforms. *One main concern, addressed by this paper, is that net-metered customers are avoiding payment of their fair share of the grid services described earlier, thereby causing those lost revenues to be recovered from other customers.* As also demonstrated in this paper, these "grid" costs are quite significant – about 55 percent of the monthly electric bill for a residential customer as demonstrated in Table 1. Although this may not have been a major problem when the DG market was in its infancy, sending the wrong price signals to both customers and to the DG industry is a major problem as the DG market rapidly grows and develops.

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6 Entergy's decision to join MISO is a recent example.

REVENUE DECOUPLING WILL NOT RESOLVE THE DG COST-SHIFTING ISSUE

Revenue decoupling is currently being used to promptly restore utility net revenues that would otherwise be lost due to declining electricity sales resulting from utility investments in energy efficiency (EE). Although revenue decoupling makes the utility whole, it does so by explicitly shifting costs from participating EE customers to nonparticipating EE customers using a public or system benefits charge (which is typically visible and transparent to all customers as a charge on their utility bills). Decoupling causes the same cost shifting problem that is created by DG with net metering. However, a fundamental difference is that the magnitude of the "cost shifting" to non DG customers is on a much larger scale than the cost shifting due to energy efficiency. A recent study revealed that decoupling rate adjustments for energy efficiency are quite small – about 2 to 3 percent of the retail rate.[7] In contrast, as described earlier in this paper, a DG customer could shift up to 55 percent of the retail rate onto non-DG customers (and, unlike efficiency charges, which are transparent, the DG cost shifting is essentially invisible to customers).

The amount of cost-beneficial energy efficiency is limited because the more you achieve, the less cost-beneficial the next increment of energy savings becomes. This "diminishing return" aspect means that energy efficiency increases only when it makes economic sense. In contrast, no such economic limit applies to DG. In fact, costs – particularly for rooftop solar PV – are expected to decline over time. *Although regulators have been willing to accept a relatively limited amount of cost shifting to promote utility investments in energy efficiency (about 2-3 percent of rates, on average), they are unlikely to accept the magnitude of cost shifting that will accompany the rapid expansion in net-metered DG unless some reforms to net metering are put into place.*[8]

ALTERNATIVE APPROACHES TO END COST SHIFTING DUE TO NET METERING

Three basic approaches to net metering are under examination across the nation, each of which seeks to ensure that a DG customer using grid services pays its fair share of the costs of those services while still receiving fair compensation for the excess energy that it produces:

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7 "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations." Pamela Morgan, Graceful Systems LLC. February 2013.

8 Distributed generation and net metering were very hot topics at the Summer 2013 NARUC meetings with at least five panel discussions addressing them.

- Redesign retail tariffs such that they are more cost-reflective (including adoption of one or more demand charges);
- Charge the DG customer for its gross consumption under its current retail tariff and separately compensate the customer for its gross (*i.e.,* total on-site) generation; and
- Impose transmission and distribution (T&D) "standby" charges on DG customers.

These three approaches are illustrative and are further described below.

Redesign Retail Tariffs (APS Proposal). To address the fundamental issue that a residential customer with rooftop solar should be compensated at a fair rate for the power it exports (sells) to the grid and also pay a fair price for its use of grid services, APS is proposing two options.[9] The first option requires the customer to take service under an existing demand-based rate schedule. The demand charge would cover a reasonable portion of the cost of grid services.

The second option allows the customer to choose an existing APS rate schedule for its total electric consumption and APS will purchase all of the customer's rooftop solar generation at market-based wholesale rates. This option ensures recovery of grid services and sends more accurate price signals to DG customers. It is also conceptually very close to what Austin Energy has already put in place.

Treat On-site Generation and Consumption Separately (Austin Energy Tariff). Austin Energy has implemented a solar tariff that fully compensates its DG customers for their gross on-site generation while separately charging them for their gross consumption under its existing retail tariff.[10] This approach effectively ensures that the cost of grid services are recovered from DG customers while also compensating DG customers for their generation at the utility's full avoided cost of procuring energy. The Public Utility Regulatory Policies Act (PURPA), under Title II, provides an established precedent for such compensation.[11] This approach requires a separate meter for on-site generation.

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9 APS conversation, July 2013.

10 Rabago, K.R., *The 'Value Of Solar' Rate: Designing An Improved Residential Solar Tariff*, Solar Industry, February, 2013. Available at www.solarindustrymag.com.

11 Although PURPA only applies to generating resources that are Qualified Facilities (QFs), this condition has not been applied if the customer receives a credit on its electric bill, rather than a monetary payment for its generated energy.

Implement T&D Standby Charges for DG Customers (**Dominion Tariff).** Dominion requires a residential net-metered DG customer with a solar installation whose rated output is greater than 10kW and up to 20kW, to pay a monthly transmission standby charge of $1.40 per kW and a monthly distribution standby charge of $2.79 per kW. However, these standby charges are respectively reduced, dollar for dollar, by the customer's transmission and distribution charges that are recovered through kWh charges applied to the customer's monthly electricity consumption up to the point where each standby charge is fully phased out. This became effective on April 1, 2012. Dominion also proposed a placeholder for a future generation standby charge, but it was not approved. The Commission ruled that a generation standby charge should be studied and filed in a future proceeding.

A FINAL THOUGHT

In light of the rapid growth in net-metered DG, it is critical that these customers pay their fair share of the cost of grid services provided to them – and sooner rather than later. Updating net metering policies to put an end to the cost shifting that is occurring today should be done now.

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IEE is an Institute of The Edison Foundation focused on advancing the adoption of innovative and efficient technologies among electric utilities and their technology partners that will transform the power grid. IEE promotes the sharing of information, ideas, and experiences among regulators, policymakers, technology companies, thought leaders, and the electric power industry. IEE also identifies policies that support the business case for adoption of cost-effective technologies. IEE's members are committed to an affordable, reliable, secure, and clean energy future.

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A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering

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January 2012

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Executive Summary

Net energy metering (NEM) is a state-level policy that permits a utility customer to generate electricity on site to offset the customer's load and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. Forty-three states, the District of Columbia, and Puerto Rico have instituted NEM in some form to permit self-generation, typically at the urging of customers seeking to use solar, wind, and other renewable energy facilities. These NEM policies vary from state to state, particularly regarding how large an individual installation can be and how much NEM will be allowed in the aggregate. Restrictions on NEM are almost always driven by utility concerns that lower utility bills for NEM customers will lead to higher utility bills for customers who do not have NEM.

The intent of this report is to provide a consistent methodology to analyze the potential rate impacts of NEM. With reliable estimates of rate impacts, regulators can make informed decisions regarding modification of NEM rules, and our intent here is to provide a methodology for more reliable estimates. In this report, we review and synthesize three studies performed for major utilities in Arizona, California, and Texas during the past decade. All three were on a scale far beyond the scope of this report, but the broad categories of costs and benefits identified in the studies are not specific to a given utility.

Based on this review, we provide a generalized approach for any state or utility to analyze the potential rate impact of NEM in its area. The analysis and results of such studies are utility-specific, but the methodology should not be. If benefits exceed costs, then regulators may want to consider lifting restrictions on NEM and crediting NEM customers for the net benefits they provide. If costs exceed benefits, then other ratepayers are subsidizing NEM customers, and regulators must decide whether externalities such as reduced pollution, job creation, and resource diversity justify the subsidy.

Costs of NEM are often argued to be the utility's lost revenue and any associated administrative costs. Every kilowatt-hour (kWh) generated by an NEM customer means one less kWh sold by the utility at retail rates. The retail rate in question depends on the type of customer. Most residential and small commercial customers have a bundled rate that covers both their utility's fixed and variable costs, while large commercial customers typically have an "energy" charge based on kWh for variable costs and a "demand" charge based on the customer's peak usage, measured in kW, for fixed costs.

Typically, an NEM solar facility has minimal impact on the demand component of the demand-metered customer's bill. Even if the customer would have experienced peak demand coincident with sunshine without a solar array, and a solar array significantly lowered demand at that time, demand near that peak level after sunset or when the system is not operating will be unchanged. Thus, typically, demand-metered customers with an NEM solar facility primarily offset energy charges, which are much lower than the bundled rates for residential and small commercial customers. As the energy charge is based on variable costs that the utility no longer has to incur, the impact of NEM for these customers should be negligible. At present, roughly two-thirds of the installed capacity of all NEM solar facilities is located on commercial customer property, with much of that sized over 100 kW and likely to be offsetting the energy charges of demand-metered customers.

The other aspect of NEM costs is the utility's administrative expense. Most utilities use proprietary billing software that is costly to adapt for NEM. Therefore, in the short term many utilities use hand billing for NEM customers to avoid incurring a large cost for a relatively small group of customers. However, over the medium to long term, changes to a utility's billing software to support evolving energy use patterns—dynamic rates, advanced metering, plug-in electric vehicles, etc.—will occur in the ordinary course of business. Logically, updating billing software to handle NEM program participants can occur as part of this longer-term evolution. Accordingly, we believe that the anticipated long-term administrative costs of a NEM program should be used in any rate impact analysis, on the reasonable presumption that billing of NEM customers will be automated.

On the benefits side of the rate impact calculation, the three studies we reviewed indicate that NEM allows utilities to save fuel expenses, avoid line losses, and realize at least some capacity benefit, while also suggesting various secondary benefits. An important component to the benefit calculation is determining what generation will be offset. Utility variable rates are based on average operating costs, and more than two-thirds of utility generation is from high capital cost/low operating cost coal, nuclear, and hydropower facilities. NEM solar facilities generally do not offset these baseload generators. Rather, they offset the lower capital cost/higher operating cost natural gas-fired facilities that operate during business hours and other periods of above-average demand to supplement baseload generation.

No matter which type of generation is offset, line loss savings are an important benefit of NEM. For every kWh generated by a utility-scale generator, five to ten percent of the electricity will be lost on the way to customers in the form of transmission and distribution losses. In contrast, NEM generation occurs at the customer's site, with almost no line loss. Neighbors typically use excess generation from a NEM facility, with negligible line losses. The demand on the distribution circuit serving the NEM customer drops by the full amount of the facility's generation at any given moment. Any line losses are utility- and time-specific, but for many utilities, higher losses occur during hot, sunny conditions. To calculate line loss savings associated with NEM solar facilities requires a reasonable estimate of average daytime line losses for that utility.

The most contentious element of the benefits calculation relates to capacity benefits. To the extent that NEM facilities allow a utility to delay or avoid construction of the next generator, transmission line, substation, or distribution line, there are clearly associated savings enjoyed by the utility and its customers. The studies we reviewed differed in their treatment of capacity benefits. We conclude that capacity benefits are real and incremental, with aggregate distributed solar generation far more stable and predictable than the obviously intermittent nature of individual solar facilities. We also include information about the potential for combining solar energy with demand response or energy storage programs to assure capacity benefits. While solar energy facilities are typically available during high demand periods, utility planners are hesitant to attribute capacity values to them because of the perception that they are not as reliable as traditional resources. Firming the output of solar energy generation with demand response or energy storage will allow utility planners to confidently rely on solar energy, particularly as new smart grid capabilities come online that allow grid operators to balance supply and demand at local levels in real time.

Author Biographies

Jason B. Keyes focuses on regulatory matters related to interconnection of distributed generation to the U.S. electric grid. On behalf of the Interstate Renewable Energy Council, he has participated in interconnection and net metering rulemakings at the utility commissions of fifteen states. As a partner at Keyes & Fox, LLP, he also represents private clients with all regulatory aspects of renewable energy project development. Prior to his legal career, Mr. Keyes managed government contracts and business development for eight years at JX Crystals Inc., a pioneer in the field of high-concentration solar energy systems. In the early 1990s, he helped develop the integrated resource plan and the demand forecast at Washington State's largest utility. Mr. Keyes received his juris doctor from the Seattle University School of Law, a master of arts in economics from the University of Washington, and a bachelor of arts from Dartmouth College. Mr. Keyes is a member of the Washington State Bar Association.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds the Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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INTRODUCTION

Net energy metering (NEM) is critical to supporting customer investment in renewable distributed generation (DG). Although there are various policy options related to NEM, the basic structure allows a utility customer to generate electricity on site to offset the customer's load and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. To facilitate the expansion of opportunities for customers to invest in DG, 43 states, the District of Columbia, and Puerto Rico have implemented NEM programs. Increasing interest in NEM programs has come at a particularly important juncture in the development of the solar industry as module prices declined markedly in 2009-2010. This decline in prices resulted in increased consumer interest in solar energy despite the economic climate. However, while many NEM programs in this two-year period broadened in scope, the quality of programs continued to vary widely between the states.

NEM programs have met with resistance, notably from utilities concerned that a robust NEM program in their service territory would result in significant rate impacts for nonparticipating customers and—in the case of an investor owned utility (IOU)—a loss of profit. Unfortunately, a detailed analysis of potential NEM rate impacts has only recently begun, so potential rate impacts are not well understood and there continues to be disagreement about the appropriate inputs for such analysis.

Despite this disagreement, efforts have moved forward, particularly in Arizona, California, and Texas, to more rigorously quantify the rate impacts of NEM programs. Together, these efforts facilitate the development of a consensus view of the most important considerations in the valuation of renewable energy resources, particularly distributed solar energy systems.

To assist state policy makers, utilities, utility regulators, renewables advocates, and other stakeholders in their efforts to evaluate the potential rate impacts of NEM in their states, we suggest a methodology based on standard NEM provisions in states with the highest levels of program participation. Because solar facilities make up the majority of net-metered facilities participating in state NEM programs, we focus on the impact of net-metered solar facilities. We analyze the methodology for determining rate impacts, and do not undertake a review of any particular state renewable energy program. In addition, we consider only the impact of net-metered solar facilities on non-participating customers' rates, not economic impacts, environmental impacts, or impacts on participating customers investing in DG resources.

The "Present Status of Net Energy Metering" section provides a background discussion focusing on the key NEM program variables that can impact rates. The "Relevant Studies for Evaluating Net Energy Metering Rate Impacts" section discusses the costs and benefits of NEM that should be considered in a rate impact analysis. The "Best Practices in Valuing Net Energy Metering" section reviews California's efforts to assess the rate impacts of NEM, which constitute the most thorough analysis to date. Finally, we present conclusions and recommendations. We cite references within the text by title or author, and include full citations in the "References" section at the end of the report.

PRESENT STATUS OF NET ENERGY METERING

NEM as a policy choice for supporting customer investment in renewable energy resources is thriving. According to the Database for State Incentives for Renewables & Efficiency *(http://www.dsireusa.org)*, 43 states, the District of Columbia, and Puerto Rico have adopted an NEM policy, as shown in Figure 1. Many states have adopted a policy that applies only to IOUs. However, some statewide policies also apply to municipal and cooperative utilities. Program rules vary widely among states on such crucial issues as overall NEM program size, facility size, allowance of third party ownership, and the ability to roll over excess generation from one month to the next.

Details on state NEM policies are thoroughly documented in an annual publication by the Network for New Energy Choices (NNEC) entitled Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures (Network for New Energy Choices, 2011). The document provides side-by-side comparison of state policies in 11 areas related to facility size, program size, eligibility, metering, treatment of excess generation, allowance of third party ownership, and protection from standby charges and other fees that nonparticipating customers do not face. Within those policy areas, NNEC awards a sliding scale of points based on the policy choices each state has made with the most points going to states with policies that accommodate more distributed generation.

For purposes of reviewing rate impacts of NEM programs, system size limitations, program size limitations, rollover of excess generation, and standby charges are discussed here. Policy choices in these areas directly affect rate impacts. These restrictions are often undertaken in an effort to address concerns about rate impacts on non-participating customers, with the intent of mitigating the perceived rate impacts of a NEM program. And yet, expansive NEM policies are an important element in state efforts to promote customer-sited renewable generation. (Itron, 2010; Doris, McLaren, Healey, & Hockett, 2009; Paidipati, Frantzis, Sawyer, & Kurrasch, 2008)

System Size Limitations

Figure 1 shows that eligible system size ranges from 20 kilowatts (kW) in Wisconsin—the size of a very large residential system—to two megawatts (MW) or more in 14 states.

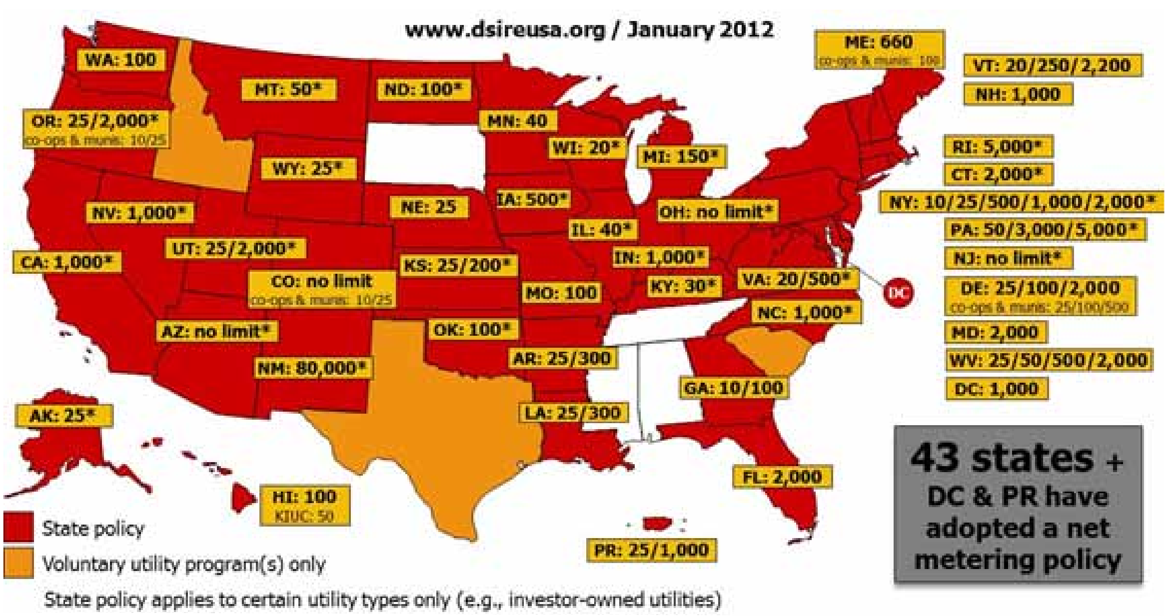

Figure 1. State net energy metering (January 2012, http://www.dsireusa.org). Numbers indicate residential/ commercial individual system capacity limits.

As Table 1 shows, the top ten states for customer-sited solar energy share the attribute of allowing NEM facilities of at least one MW, with the exception of Hawaii, which has unique characteristics.

TABLE 1
Top 10 States by Installed Capacity and Their NEM System Size Cap

2010 Rank by State	2010 Market Share	Cumulative MWDC	NEM System Size Cap
1. California	48%	1,022	1,000 kW
2. New Jersey	12%	260	no limit
3. Colorado	5%	117	no limit
4. Arizona	5%	105	no limit
5. Nevada	5%	102	1,000 kW
6. Florida	3%	73	2,000 kW
7. New York	3%	56	2,000 kW
8.Pennsylvania	3%	55	5,000 kW
9. Hawaii	2%	45	100 kW
10. New Mexico	2%	43	80,000 kW
All Other States	12%	261	

Source: Sherwood, L., ***U.S. Solar Market Trends 2010****, Interstate Renewable Energy Council, June 2011. (Total of 2,139 MW_{DC})*

Program Size Limitations

Limitations on program size and the size of eligible systems often go hand in hand. These policies appeal to those who believe that NEM programs are a subsidy, but this position is widely debated. A December 2009 report by the National Renewable Energy Laboratory reviewed how states have considered the rate impacts issue, with no example of a state finding that subsidization exists (Doris, Busche, & Hockett, p. 15). The report notes that North Carolina and Maryland looked into the issue and decided not to attempt studies because the experience in other states "had not shown a negative rate impact." The report notes that in New York, an attempt at quantification was underway, but "the impacts have not been large enough to measure under the current data collection scheme." Having surveyed states on the issue, the report concludes that "[t]he states that have increased the net metering system size cap generally cited the limited impacts of net metering on ratepayers in other states."

These policy choices also hinder the development of renewable energy markets in two ways. First, program capacity caps signal to potential new energy developers that their efforts will ultimately be thwarted, not by a lack of customer interest, but by regulatory restrictions. At the same time, a cap on DG system size to less than one MW precludes development of economical systems above the size cap, and those larger systems have been an important driving force in market growth during the past few years. In the end, both policy choices signal to developers that their investments in building solar businesses are best made elsewhere.

Rollover of Excess Generation

At the heart of any NEM program is the treatment of generation in excess of a customer's needs. When implemented properly, NEM has nearly the same impact on a participating customer's utility bill as would occur if the customer-generator used a bank of batteries to store energy until the customer's demand exceeded his or her generation (batteries have modest losses, so NEM has a slightly greater utility bill impact). At its most basic, NEM allows a customer's meter to run backwards when the customer produces more power than the customer can use. (Note that most mechanical meters can actually run backwards, but for newer digital meters, "running backwards" is figurative.) States that do not allow this basic aspect of NEM simply do not "net meter" in the widely accepted understanding of the concept.

Once treatment of instantaneous excess generation is addressed, policy makers must consider the treatment of generation at the end of a particular billing period as they develop program rules. The most expansive net metering policy is to allow for indefinite rollover of net excess generation from billing period to billing period until it is used by the customer-generator. This policy choice provides the greatest flexibility in allowing customers to design a renewable energy system to meet their individualized needs, given the variations in output from a system over the course of the year and a customer's yearly consumption pattern. For many homeowners seeking to meet their entire annual load, solar energy generation in the sunny summer months exceeds their summer loads, with the excess offsetting loads in the winter.

Perpetual rollover of excess generation also avoids possible federal regulatory issues related to wholesale sales and addresses concerns that NEM might produce incentives for customers to oversize their systems. As well, the Internal Revenue Service has indicated in at least one private letter ruling that payment for excess generation is taxable income.

Stakeholders with concerns over the rate impacts of NEM often attempt to limit possible rate impacts by requiring the customer-generator to donate net excess generation at the end of a calendar year or some other twelve month period to the utility or to accept payment for the net excess generation at the utility's average avoided cost. Both of these program choices undervalue the net excess generation a customer provides to a utility by providing no value or valuing the on-site, customer-owned renewable energy generation at the cost of fossil fuel generation. NEM programs almost always have a requirement that systems be sized to meet no more than the customer's expected consumption, so substantially oversized systems are not built. Treatment of annual excess generation is an issue for the odd year when generation was higher than expected or consumption was lower than expected. Perpetual rollover of excess generation avoids the administrative burden of an annual reconciliation and gives the customer an assurance of credit for all energy delivered to the utility.

Standby Charges

There have been many instances of utilities proposing special tariffs for customer-generators structured as standby charges or other fees to compensate the utility for possible services that the utility provides. A utility's regulator—the state public utilities commission for IOUs, the city council for many municipal utilities, and other boards for various co-ops and public utility commissions—must approve such tariffs. From another angle, some utilities have argued that any requirement that standby charges or fees may not be imposed is an unwarranted subsidy by nonparticipating ratepayers. Unfortunately, this argument does not account for the fact that standby charges were generally developed as a rate option for much larger cogeneration or combined heat and power facilities that supply energy on a steady 24/7 basis. These generators lower a customer's peak demand, and therefore the customer's demand charge, while their utility stands by to meet the customer's entire load if the generator fails. Solar energy generation ceases every night and dips during daytime due to cloud cover. For most commercial customers, this means that the utility will impose a demand charge based on peak demand that is nearly what the customer would pay without a solar generation facility. While residential customers typically do not have demand charges and can reduce their utility bills to nothing with NEM depending on facility size, the utility is still in the favorable position of receiving daytime energy that is more valuable than nighttime energy, and typically at least as valuable as early evening energy.

Because of these concerns, Freeing the Grid gives state programs that institute standby charges and other fees for net-metered systems fewer or even negative points. To the extent that proposed standby charges are based on actual rate impacts for a particular utility, institution of the charges is a policy choice available to regulators, but an NEM policy should be reviewed without standby charges to determine what rate impacts exist.

Relevant Studies For Evaluating Net Energy Metering Rate Impact

As solar has become a viable option for increasing numbers of consumers, considerable federal, state, and utility attention has begun to focus on valuation of solar energy from DG resources. The following three sections offer a review of recent solar valuation studies, recent efforts in California to develop a methodology for valuing demand-side resources including solar energy systems, and recent efforts to value the capacity benefits provided by solar energy systems. Synthesis of these efforts will provide insight into areas of consensus on the valuation of solar and, therefore, form the foundation of best practices for assessing the rate impacts of NEM.

Studies Valuing the Benefits of Solar Resources

There have been several efforts to value solar energy generation in specific locales, of which three stand out as particularly comprehensive. The first two are discussed in this section: The Value of Distributed Photovoltaics to Austin Energy and the City of Austin (Hoff et al., 2006, followed by a 2008 revision) (AE study) and Distributed Renewable Energy Operating Impacts and Valuation Study (R.W. Beck, Inc., 2009) (APS study). The third comprehensive study of solar energy valuation is incorporated within a broader review of the costs and benefits of net metering for California's largest IOUs. We review that study in the "California's Cost-Benefit Methodology for Distributed Energy Resources" section.

The Austin Energy (AE) and Arizona Public Service (APS) studies discussed below provide an in-depth look at the value solar photovoltaic (PV) generation can bring to the grid for a specific utility. Moreover, each study was subject to scrutiny from many perspectives and stakeholders, and, taken together, they represent a good starting point for identifying consensus elements of the value solar PV can bring to the grid.

Austin Energy Study

To support its determination to move forward with a goal of installing 100 MW of solar generation by 2020, Austin Energy commissioned Clean Power Research to quantify the benefits of solar generation to the utility. At the onset, the authors identified two perspectives as forming the core of the AE study—the "utility" perspective and the "all ratepayer" perspective—and the study's authors used these perspectives to inform the development of a methodology for valuing the benefits of distributed PV.

Based on the various perspectives, the AE study authors presented a comprehensive list of benefits stemming from distributed PV based on research performed by the National Renewable Energy Laboratory, and including the value of energy production, generation capacity value, transmission and distribution (T&D) deferrals, reduced transformer and line losses, environmental benefits, natural gas price hedge, disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control. Ultimately, the last four potential benefits listed here were not included in the AE study for various reasons, and the benefits associated with disaster recovery were studied, but not included in the primary analysis. (Hoff et al., 2006, p. 12).

The AE study found that PV offered a present value of $1,983 to $2,938/kW or on a levelized basis between 10.9¢ and 11.8¢ per kilowatt-hour (kWh) in 2006 dollars. In a 2008 recalculation, Austin Energy found substantially higher average values of $3,139/kW and 16.4¢/kWh in 2008 dollars.

From the standpoint of NEM, when a customer receives a credit for excess generation that can be used when consumption exceeds generation, Austin Energy's residential retail rate as of December 2010 on tariff E01 (the standard residential tariff), including a fuel adjustment of 3.65¢/kWh, is approximately 7.2¢/kWh for less than 500 kWh of consumption per month, 9.67¢/kWh for consumption of more than 500 kWh/month from November through April, and 11.47¢/kWh for consumption of more than 500 kWh/month from May through October. All of these rates are well below the 16.4¢/kWh unadjusted value of the benefits PV brings to Austin Energy.

Discussion of AE Study

In reaching these figures, it is important to note that ultimately, two important benefits were not included in the final valuation—disaster recovery and reactive power control.

Disaster recovery benefits were not included because the quantification of this benefit was the first known attempt to do so by the authors and, therefore, the results did not have the level of certainty desired. Ultimately, the authors of the study recommended further study of the issue by Austin Energy in combination with battery storage especially in the context of a hybrid electric vehicle program. Disaster recovery benefits were estimated to be $2,701/kW for capacity and for energy generation to range from $1,121 to $1,578/kW. These numbers would almost double the overall value of PV generation to Austin Energy.

Voltage support and reactive power control had a value of $0/kW in the final model because current technical standards do not allow for this benefit to be provided by inverters for the benefit of utility operators. The study estimated the value of this benefit at up to $20/kW, but the figure could be much higher, and the technology to provide this benefit is available. At present, the technology may not be incorporated into inverters pursuant to IEEE Standard 1547, the existing technical standard for interconnections. A working group of electrical engineers is developing a standard for interconnection of generation with inverters that provide reactive power and voltage support, which will become IEEE Standard 1547.8.

A recent study by the Electric Power Research Institute includes the graphic in Figure 2, displaying how voltage is less variable on a typical 12 kV circuit with solar energy and voltage control than it would be with no solar energy facilities at all. Already, New Jersey utility PSE&G (Public Service Electric & Gas Company) has mounted tens of thousands of individual solar modules on its power poles and is using the available voltage and reactive power support (as a utility, it does not need to wait for completion of IEEE 1547.8). Because of these developments, in any valuation of solar energy generation, it now seems reasonable to consider the value of voltage and reactive power support.

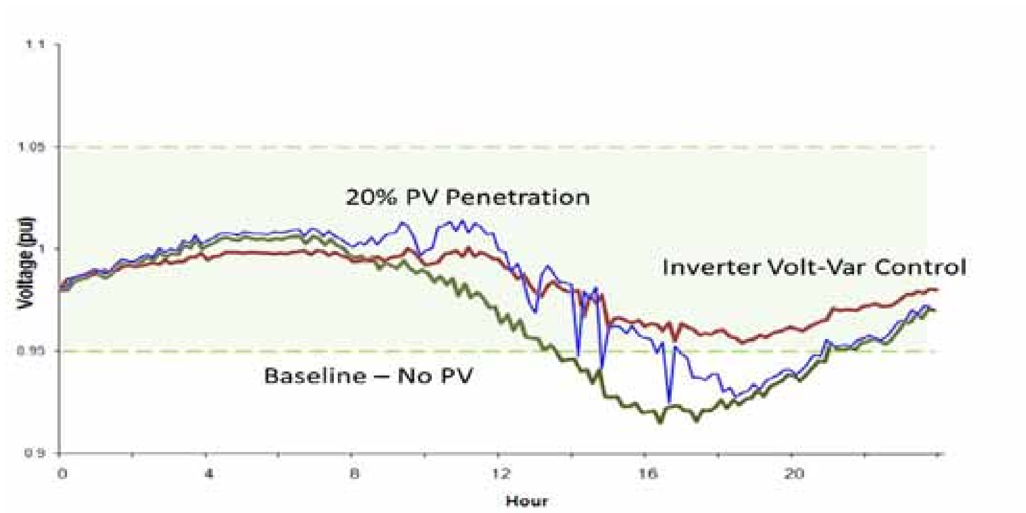

Figure 2. Percentage variation from rated voltage on a typical 12 kV line without PV (the green line, with lowest point), with 20% PV penetration without voltage and reactive power control (the jagged blue line), and with "Inverter Volt-Var Control" (the brown line, with the least voltage variability). Source: Seal, B., Monitoring, Information, and Control: Management for Tomorrow's PV (PowerPoint), May 2010 (reprinted with permission).

Arizona Public Service Study

In early 2008, Arizona Public Service (APS) commissioned R.W. Beck, Inc., Energized Solutions, LLC, Phasor Energy Company, LLC, and Summit Blue Consulting, LLC to assess the impact of wide-scale deployment of distributed PV along with solar hot water systems and commercial daylighting systems on the APS system. Among the specific objectives of the study was an assessment of the benefits wide-scale deployment of these technologies could have for the APS system. In this sense, the APS study views the potential benefits of deployment of distributed solar from the utility perspective. The APS study was conducted in an open process with the participation of many stakeholders from within the solar industry, the business community, advocates, and the regulatory community.

In constructing the methodology for reviewing the benefits of the three distributed solar technologies discussed above, the study's authors focused on low, medium, and high penetration scenarios, with generating capacity as a percent of peak demand reaching 0.5%, 6.4%, and 14% respectively by 2025 (Arizona Public Service, 2010, Tables 5-3 and 5-4). Within these scenarios, the authors made a number of assumptions about PV capital cost reductions, the availability of federal tax credits, and the make-up of APS tariffs. The APS study also developed a target scenario that assumed APS would deploy solar technologies to achieve the greatest possible benefits. The target scenario included a general scenario and one in which all commercial PV used single-axis tracking.

The benefits identified in the APS study included reduction in T&D line losses, deferment of T&D capacity upgrades and additions, reduction in necessary equipment size within the distribution system, avoided electric generation capacity costs, avoided fixed operating costs, avoided energy purchases, and avoided fuel purchases. While labeled differently, this is a subset of the list used by the AE study, leaving off environmental benefits and the ability to provide a hedge on natural gas prices, as well as the four factors ultimately left out of the primary AE analysis (disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control).

After detailed modeling, the APS study found a range of benefits across the various penetration and target scenarios of approximately 7.9¢ to 14.1¢/kWh in 2008 dollars, without reference to a particular scenario (Arizona Public Service, 2010, p. xxii). Residential rates for APS customers as of December 2010 were just under 9.4¢/kWh, ramping up in stages during summer months to 17.4¢/kWh for higher energy usage. Assuming benefits have increased with inflation, the APS study appears to be inconclusive regarding whether there is a subsidy flowing from residential ratepayers to NEM participants (calculated benefits at the lower end of the reported range are less than costs). For demand-metered customers, it seems that benefits exceed costs substantially.

An APS review of this report stated that benefits identified in the APS study were based on locating facilities optimally and maintaining utility ownership and control of the installations, although the benefits of optimal siting are not broken out separately in the APS study. The most likely benefit of selective siting would be for individual distribution circuits. Most transmission and generation benefits would accrue regardless of the location of NEM systems. Reported distribution system benefits are only 0 to 0.31¢/kWh, implying that the impact of selective siting is relatively modest.

Discussion of APS Study

Two important aspects of the APS study directly affect the extent of the benefits it found, and explain the substantial difference from the AE study results.

First, virtually no capacity benefits were identified for the years prior to 2025 and even then, the capacity benefits were only significant in the high penetration case. The study notes that capacity pricing is rolled into energy prices used to calculate the energy benefit, and in that sense, there is a capacity value. However, by “capacity benefit” we are only referring to deferral or avoidance of new utility-built generation and T&D. The APS study’s rationale for not attributing capacity benefits was that T&D and utility generation investments are “lumpy” so it would take a great deal of DG to have an impact on those investment decisions. (Arizona Public Service, 2010, p. 6-9). This view takes a primary advantage of PV—the ability to be installed incrementally—and gives it no value until output from the PV installation fully displaces a new utility generator. APS notes that its Integrated Resource Plan calls for no new construction for the next seven to eight years because it has sufficient capacity at present, but the PV installed over the next eight years could push the need for new construction out further and should be attributed some value. APS expects that peak demand will grow by 4,170 MW from 2010 to 2025. (Arizona Public Service, 2010, Table 5-6) and it is reasonable to assume that even a modest level of DG would defer some quantity of system level utility investments by a year or more, thereby saving ratepayers money by deferring investment in these lumpy assets. In conjunction with modest levels of demand response, as discussed later in this report, installed solar facilities could also provide APS with firm power, eliminating the need for at least some portion of its contemplated generation and T&D investments.

The APS study makes a jump from modest penetration levels in 2015 to high penetration in 2025 without analyzing impacts in between. Even the high scenario assumes only 63 MW of DG by 2015 (Arizona Public Service, 2010, Table 5-3), or roughly 0.7% of anticipated peak demand for APS in 2015 (Arizona Public Service, 2010, Table 5-4). By comparison, DG capacity in PG&E's service territory in California is more than 2% of PG&E's peak demand as of early 2011. While the APS study looks at 6.4% and 14% penetrations in 2025, it would have been interesting to present capacity benefits in the 2% to 5% range that are likely in earlier years.

The second significant deficiency in the APS study is that it does not consider the benefits at the optimal penetration level using the optimal orientation. Because the study is "forward looking" in so far as it is not assessing the impacts of a program as currently implemented, it would seem logical to have performed this analysis. Indeed, the study acknowledges that southwest facing modules or solar tracking will increase production per MW in the late afternoon, when APS experiences peak demand, and have a greater capacity benefit than a south facing array of the same size. However, the scenarios describing the benefits of DG under the low and medium penetrations do not appear to take the capacity benefits of deploying these optimally oriented arrays into consideration.

Interestingly, in the high penetration case, a solar tracking sensitivity analysis concludes that in 2025, tracking would shift the APS peak to a later hour, at which time the capacity benefit would be little more than it would be with a fixed array pointed south. However, this case envisions generating capacity of 1,677 MW (Arizona Public Service, 2010, Table 5-3), which would be 14.6% of peak demand. The analysis has thus skipped from a modest penetration of 0.7% (63 MW) in 2015 to a penetration of 14.6% in 2025 without looking at the optimal penetration that would occur in between. To its credit, the APS study does acknowledge that energy storage would increase the capacity value of solar energy systems, but it does not attempt to quantify the benefit.

Finally, the APS study did not attribute any environmental benefits to the utility or quantify natural gas hedging benefits as the AE study did. Inclusion of these benefits would have contributed to an overall valuation of the benefits to utility ratepayers from the solar resources modeled in the study. And like the AE study, the APS study did not attribute any value to the ability of solar generation to provide voltage and reactive power support or to provide disaster recovery benefits.

California's Cost-Benefit Methodology for Distributed Energy Resources

Starting in 2004 in Rulemaking (R.) 04-03-017, the California Public Utilities Commission (CPUC) embarked on an effort to develop a framework for valuing distributed energy resources. The overarching goal of the proceeding was to develop a methodology planners could use to compare demand-side resources in a consistent fashion across all resources—energy efficiency, renewable distributed generation, combined heat and power, etc. Efforts by numerous parties including renewable energy and combined heat and power advocates, CPUC staff, ratepayer advocates, and utilities to develop this methodology went on for a number of years and into successor distributed generation dockets R.06-03-008 and R.08-03-008. Stakeholders' efforts culminated in the issuance of Decision (D.) 09-08-026 on August 20, 2009.

In D.09-08-026, the CPUC established a methodology for valuing a wide range of distributed energy resources based on the approach used to value energy efficiency in California's Standard Practice Manual (SPM). In that vein, D.09-08-026 considers four tests described in the SPM for use in evaluating DG resources—the participant test, the rate payer impact (RIM) test, the program administrator (PA) test, and the total resource cost (TRC) test. Ultimately, the CPUC chose to use four tests—the participant test, the PA test, the TRC test, and the societal test—in evaluating DG resources. The societal test is very similar to the TRC test, but includes the impacts of externalities such as environmental costs/benefits, excludes tax benefits, and uses a different discount rate. Each of these tests views the costs and benefits of DG resources from different perspectives—the participating customer-generator (participant test), ratepayers generally (the RIM test), society (TRC and societal tests), and the program administrator, which in California is often the utility (the PA test).

Although D.09-08-026 does not require the use of the RIM test for a general evaluation of DG resources, the test is relevant to a discussion of the rate impacts of NEM because the RIM test attempts to compute bill and rate impacts due to changes in utility revenues and costs. D.09-08-026 identifies the following benefits within the RIM test—avoided T&D line losses, avoided energy and resource adequacy costs, T&D investment deferrals, environmental benefits, increased revenue from fuel transportation for natural gas-fired DG (not relevant for solar energy), and reliability benefits (ancillary benefits and volt-ampere reactive [var] support).

Unlike the AE and APS studies, the CPUC decision also identified costs, including net metering bill credits, program administration, reduced revenue from standby charge exemptions, lost revenue from non-bypassable charges, reduced T&D and non-fuel generation revenues, increased reliability costs for ancillary services and var support, cost of utility rebates or incentives, the cost of utility interconnection not charged to customer-generators, and increased utility fuel transportation costs for gas-fired DG (not relevant for solar energy).

Discussion of D.09-08-026

Inclusion of lost revenues must be handled very carefully in the context of NEM of intermittent resources such as solar and wind. In theory, the utility has a right to recover certain fixed costs under its standard tariffs, and NEM cuts into that expected recovery. However, great care must be taken to avoid double counting of costs. For instance, D.09-08-026 recognized that inclusion of lost standby charge revenue could result in double counting of lost T&D revenues, because standby charges developed in California were also designed to recover T&D expenses. Because both revenue streams would be recovering the same T&D expense, recovery of lost standby charge revenue along with recovery of lost T&D revenues could result in double counting of lost T&D revenues.

Additionally, practitioners must consider other factors when addressing lost revenue claims. First, utility standby charges are designed to recover the utility's cost of being constantly prepared to meet a customer's peak demand in the event that on-site generation is not functioning at the time of that peak demand. In the case of intermittent resources, it is a near certainty that generation will not be effective at some time during each billing cycle when the customer's demand nears the customer's peak demand. In other words, at those times, the customer's solar array is providing minimal generation to offset the customer's electricity consumption, and the customer will pay a demand charge based on almost all of the customer's peak consumption. For demand-metered customers in this situation, the demand charge resulting from their peak demand is already at or very close to their peak consumption, so the utility is not standing by, it is providing the necessary power and charging for it already. Claiming that preclusion from billing standby charges is a utility cost is effectively claiming that the utility can bill the customer twice for fixed costs, which obviously is not correct. Double counting would almost certainly occur if potential lost standby charge revenue is included as an additional cost of the NEM of intermittent resources.

Moreover, although residential and small commercial customers do not face demand charges, the variability in their relatively small loads due to renewable generation has not been shown to have any significant impacts on the grid or been shown to be potentially any different than customers without renewable generation who have significantly varying loads from one moment to the next. Accordingly, requiring that these customers pay standby charges would be discriminatory in the absence of a cost of service study showing a clear justification for such charges.

These are not abstract concerns. For example, when Southern California Edison (SCE) undertook a more detailed review of its standby charges in light of the diversity of standby customer load compared to regular retail load, SCE found that the diversity of standby customer load was imposing significantly less cost on the distribution system than its regular tariffed customers. Accordingly, SCE redesigned its standby charge rates by reducing demand charges when compared to regular tariff services. Looking at this change in reverse, prior to the change in demand charges, standby customers were significantly overcompensating SCE under its prior standby charges. It would be useful to see whether customer investment in renewable energy similarly results in a greater diversity in their load when compared to typical retail customers, and has a similarly less taxing impact on the grid.

In sum, inclusion of lost utility revenue related to standby charges has some logical appeal and merit, but care must be taken to avoid double counting. Moreover, standby charges and T&D charges designed to recover costs from ratepayers who have not invested in DG resources may overcompensate the utility in the absence of cost of service studies specific to DG customers, which would set these fees in that context. That is, calculating lost revenues based on these tariffs could overstate the amount of the utility's lost revenue.

California's Net Energy Metering Cost Effectiveness Evaluation

In late 2008, the CPUC commissioned Energy and Environmental Economics, Inc. to value the excess generation produced by net-metered systems for the state's three largest IOUs—Pacific Gas & Electric (PG&E), SCE, and San Diego Gas & Electric (SDG&E). The resulting study, Net Energy Metering (NEM) Cost Effectiveness Evaluation (Energy and Environmental Economics, Inc., 2010) (E3 study), was publicly issued in March 2010 (dated January 2010). The study delves into detail by utility, customer class, customer size, and location not seen in any other study.

E3 Study Overview

As part of its focus on the costs and benefits of net-metered solar generation from the utility perspective, the E3 study provides the country's first comprehensive look at the rate impacts of NEM, making it uniquely important in this report. Although it does not reference the RIM test discussed above, the E3 study relies heavily on the analysis performed in D.09-08-026. Because of that fact, despite the groundbreaking nature of the E3 study, many of the flaws and concerns discussed above are present in the E3 study.

The benefits of NEM provided in the E3 study are similar to those in the AE and APS studies. For the E3 study, they include avoided costs from avoided energy purchases, avoided generation capacity or resource adequacy, avoided line losses, avoided T&D capacity, avoided environmental compliance, avoided ancillary services, and avoided renewable energy purchases by the utilities under California's Renewable Portfolio Standard.

On the cost side of the equation, the study evaluated the cost of bill credits provided to NEM participants, administrative costs, and interconnection costs (under California law interconnection costs are not billed to NEM customers).

While the complexity of the analysis in the E3 study precludes a detailed discussion of the methodology here, one example highlights the comprehensive nature of the study. Recognizing that the impact of NEM will not be uniform for all customer-generators, the E3 study models the impacts in 1,253 distinct customer-groupings based on utility, customer type, facility sizing in relation to customer load, and location. (Energy and Environmental Economics, Inc., 2010, p. 29) The complexity of such an undertaking is daunting, but it is important to accurately reflect the timing, size, cost, and benefits of exported energy. Additionally, to further explore the impact of certain cost assumptions on the analysis, the E3 study includes a sensitivity analysis related to billing costs, T&D avoided costs, standby charges, and interconnection costs.

Overall, the E3 study finds that current rate impacts average just over a hundredth of a cent for every kWh purchased (0.011¢/kWh, Energy and Environmental Economics, Inc., 2010, Table 4). Delving more deeply into the average figure, the results for each utility were 0.018¢/kWh for PG&E, 0.0005¢/kWh for SCE, and 0.0009¢/kWh for SDG&E. These are truly small figures; utility rates often rise by a penny or more per kWh in a utility rate case, and the figures here are all less than a fiftieth of a cent.

Looking to the future, the E3 study finds that by 2020, 2,550 MW of net-metered solar generation will result in a 0.38% increase in utility rates or 0.064¢/kWh (Energy and Environmental Economics, Inc., 2010, Table 5). In 2020, 2,550 MW of generation would be 3.7% of forecast peak load of just over 60,898 MW for the three utilities. (California Energy Commission, December 2009, p. 51—adding coincident peak demands for PG&E, SCE, and SDG&E). Taking the facts provided here, for every 1% of solar generation, as a percentage of utility peak demand, the E3 study indicates a 0.1% impact on utility rates.

Discussion of the E3 Study

Although the E3 study concludes that NEM at the California IOUs entails a modest subsidy of customer-generators by other ratepayers, several assumptions drive that conclusion.

First, an important assumption made in the E3 study is that the rate impact of NEM is limited to the impact of exported energy. The study notes that customers can generate electricity without NEM, but would not be able to export. With this approach, rate impacts related to energy used on site at the time of generation are not impacts of NEM, they are impacts related to solar generation generally. The study notes that 243 customer-generators with a total of 43 MW of generating capacity do not export at all, and are excluded from the impact analysis entirely. (Energy and Environmental Economics, Inc., 2010, p. 14). While the E3 study does not say it, this approach implicitly assumes that without NEM in place to support customer-generators, customer-generators would have installed the same amount and type of generation, would not have changed their consumption patterns to make better use of their renewable energy investments, and, finally, that excess generation would be delivered to utilities for minimal compensation. This is not a likely outcome.

In the absence of NEM, there would still be federal and state incentives to install solar energy facilities along with the incentive of offsetting coincident customer load, but customer-generators would likely behave differently. On the one hand, some facilities might be sized smaller to reduce the amount of excess generation. Exported energy could still be sold at the utility's avoided cost in accordance with federal law, but that is less than retail rates, and customers could be expected to react to that lower payment. On the other hand, customers would be likely to try to better coordinate generation and consumption in the absence of NEM, to increase the percentage of generation used on site. For example, air conditioning equipment could be operated in conjunction with generation, cooling more at mid-day and less in the late afternoon. As well, customer-sited batteries could allow customers to synchronize inter-day generation and load for a modest additional investment.

It would be difficult to model generation and load in the absence of NEM, and it is understandable that the E3 study made the simplifying assumption that customers with solar energy facilities would not attempt to match generation and load in the absence of net metering. However, as a practical matter, the reported rate impact of NEM is probably overstated, because customer-generators would modify their behavior in the absence of an NEM program.

Second, it is important to recognize that the E3 study bases costs on the rates that utilities would have charged customer-generators, and California's IOUs have some of the highest residential rates in the country. For example, a residential customer exporting 1,000 kWh in a year will get a credit for 1,000 kWh from the customer's utility, which means the utility did not have the opportunity to sell that amount of energy to the customer for as much as 40¢/kWh. In many parts of the country, top residential rates are less than 10¢/kWh, and utilities' lost revenue from NEM is therefore much lower.

Additionally, the E3 study suffers from several deficiencies that, when looked at cumulatively, greatly decrease the value of the benefits from the energy provided by net-metered customers. Most importantly, the study finds that the utilities have limited need for additional capacity until 2015, so the study provides customer generation with limited credit for capacity value until after 2015. The E3 study values capacity starting at $28/kW/yr in 2008 and increases linearly to $141/kW/yr in 2015, then increases at a more modest pace to more than $200/kW/yr by 2036 (Energy and Environmental Economics, Inc., 2010, Appendix A, p. 15-16).

Broadly, this assumption implies that utility planning occurs without consideration of customer generation, and accordingly assigns a limited capacity value for customer-sited generation. This assumption simply does not square with current practice in California for a number of reasons. First, long-term resource planning in California does include customer-sited generation because the utilities' long-term resource acquisition plans rely on load forecasts based on historical loads that include customer-sited generation and anticipated future customer-sited generation. Second, the California Energy Commission recently denied an application to build the natural gas fired Chula Vista plant based partly on the fact that significant solar DG would be coming online. So both in theory and practice, customer-sited DG is being taken into account in long-term decision-making on the need for generating capacity.

Interestingly, the E3 study's valuation of the capacity benefit of NEM solar generation is considerably lower than the likely valuation of capacity for solar energy purchased by California utilities under long-term contracts. While still under consideration, it appears that the market price referent (MPR) will be used for these contracts (other than the contracts under the Renewable Auction Mechanism). The MPR is based on the total cost of generation for a natural gas combustion turbine, including capital costs, and thus incorporates capacity value. It has been argued that solar energy under contract has more value than NEM solar energy because there is no assurance that the latter will continue to operate. However, there is no reason to expect widespread decommissioning of NEM systems. Having paid to install their systems, NEM customers are unlikely to remove them and forgo utility bill savings, and there are very few instances of such actions to date. It seems reasonable to give NEM generation the same capacity credit accorded to solar energy purchased under long-term contracts.

To highlight the significance of this flaw in the study's methodology, an added capacity value of even a \$20/kW/yr increase, applied to 2,550 MW of solar generation, is \$51,000,000 per year—a significant added benefit that would negate much of the net cost per year of NEM in the E3 study. For other states and utilities attempting to value capacity, the lesson is that to properly determine capacity value, a base assumption should be that the generation was anticipated, or should have been anticipated, and its value should not be assessed after the utility has made its generation choices and has sufficient generation. At the margin, a prudent utility has sufficient capacity and there is limited value to adding more capacity.

The other important factor not considered in the E3 study is reactive power and voltage support, as discussed earlier in this report. D.09-08-026, identified var support as an NEM cost, presumably based on the assumption that fixed-voltage inverters on solar energy facilities might cause greater voltage fluctuations on the circuit. As discussed earlier, new technology and revised standards will allow inverters to provide adjustable voltage support and var control. While current utility infrastructure does not enable utilities' use of these functions, the implementation of smart grid with associated communications and controls enhancements offers the strong potential to turn this presently deemed cost into a future benefit.

Administrative costs are identified in the E3 study as well, based on reported utility costs. Monthly incremental administrative costs for residential net-metered customers are a reported \$18.31 for PG&E, but only \$3.02 for SCE and \$5.96 for SDG&E. (Energy and Environmental Economics, Inc., 2010, p. 40) As noted above, to further explore the impact certain cost assumptions have on the results, the study performed sensitivity analysis. As part of that analysis, the study took a closer look at administrative costs, including a sensitivity analysis based on no administrative cost (the base case accepts the PG&E cost). This sensitivity analysis resulted in a 27% decrease from the base case. This sensitivity analysis is reasonable to consider because, while in practice there is some minor administrative cost per customer, that cost is likely to drop with automation and high volume. An overstatement of \$12/mo for systems averaging 6 kW in PG&E's service territory is equivalent to roughly \$24/kW/yr, implying an added cost of roughly \$24,000,000 per year, which seems unreasonable.

Automation of billing to handle NEM over the long term is sensible as part of an overall update of utility billing software to support the move to a smart grid that supports distributed generation. A holistic view of the necessary changes to utility billing practices is also required to support investment in the smart grid. These changes include the need to accommodate NEM, demand response, advanced energy storage, vehicle electrification, and other necessary initiatives. All of these long-term policies have been identified as necessary to meet climate and environmental goals and therefore should not be viewed in isolation. In particular, smart metering has been justified based on traditional utility cost savings, and should allow administrative costs for NEM and other programs to drop to very low levels.

As noted earlier, it is critical to recognize that California IOUs have tiered rates as high as 40¢/kWh, so the lost-revenue cost to the California IOUs is two to five times higher than most utilities in the United States. In fact, the top rate at PG&E contemplated in the E3 study was 50¢/kWh, although that tier has since been eliminated.

Quantifying the Capacity Value of Solar

Because the capacity value for PV has been a particularly thorny issue in determining the value of solar resources for utilities, it is worthwhile to provide more discussion on this topic. For many utilities, peak demand typically occurs in the late afternoon. This fact is often cited as a key reason to dismiss the ability of solar to provide significant capacity benefits. However, depending on the actual hour of peak demand, modules can be oriented to the southwest to enable them to operate near their rated capacity in the late afternoon. Careful program design that encourages customers to orient their solar resources to meet a later system peak can address this concern. As discussed in the APS study, southwesterly oriented modules operate at more than two-thirds of rated capacity from 5:00 to 6:00 pm on a sunny summer day and at half of rated capacity from 6:00 to 7:00 pm. Moreover, modules pointed southwest are operating at only slightly less than their rated output between 3:00 and 4:00 pm, which was the peak load in California for 2008 (Self Generation Incentive Program Impact Report, 2008 revised).

The second challenge to solar energy's ability to provide capacity reliably is that cloud cover can dramatically impact an individual system's performance on short notice. In practice, the effect of cloud cover on a single solar energy system is not simultaneously felt across a whole region, and much of the variability is not even seen across a distribution circuit with multiple MW of interconnected generation. Perez et al. showed that just twenty systems over a limited service area will have a collective output with almost no variability on a partially cloudy day, despite the variability of each one of the systems individually (Perez et al., 2006). Likewise, researchers at Lawrence Berkeley National Laboratory recently calculated the smoothing effect of distributed solar power, finding that the relative aggregate variability of PV systems decreases with increased geographic diversity. That study showed aggregate variability over a 15-minute period is one-sixth of the variability of a single PV system, and over a one-hour period, it is one-third of the variability of a single PV system (Mills & Wiser, 2010).

Demand response or energy storage coupled with PV can play a role in meeting peak demand if peaking generation is not available at lesser cost. In a 2006 study, Perez et al. (Perez et al., 2006) analyzed the peak-month loads for three utilities and the coincidence of available solar generation. Stunningly, almost all of the loads above 90% of the utilities' peak load could be met with solar energy, with a minimal contribution provided by demand side management to fill in the gaps, as shown in Figure 3. In practical terms, these results show that solar energy is able to provide reliable energy peaking generation as needed with only a modest addition of demand side management.

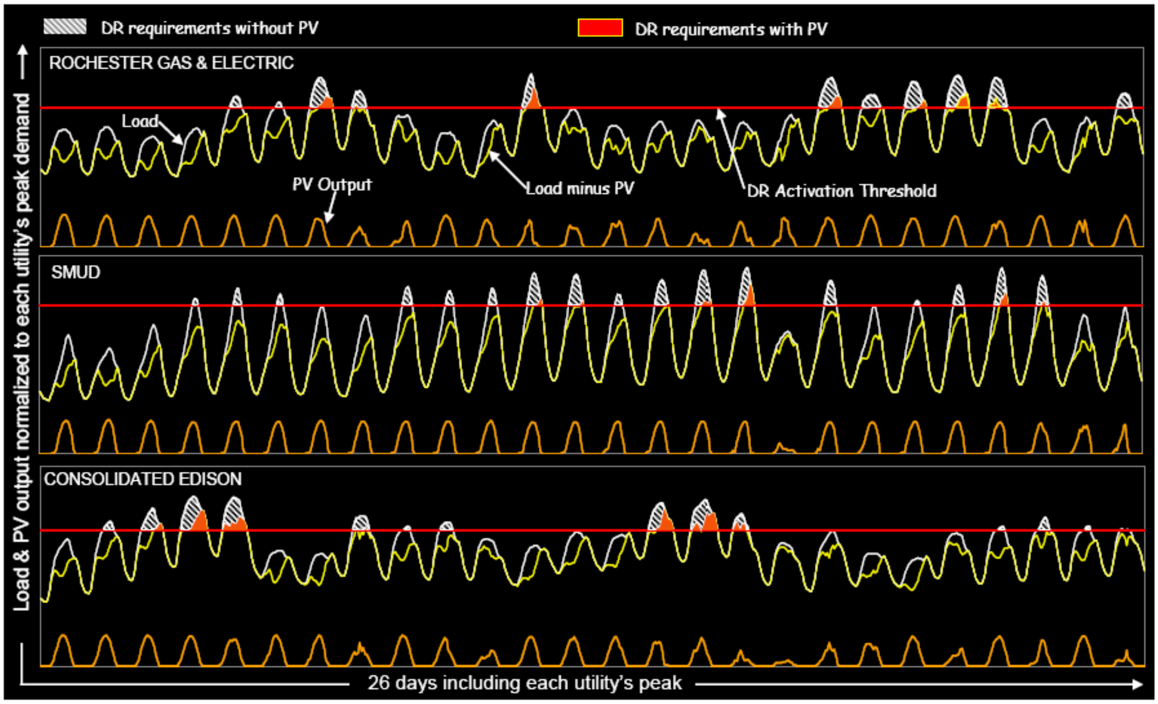

Figure 3. Integration of PV in demand response programs, using PV rated capacity of 20% of utility peak demand and showing the peak line at 90% of utility peak. Solid shading indicates periods of demand side management. Source: Perez et al., 2006.

In sum, research has demonstrated that many of the concerns that lead utility planners to discount the capacity value of PV can be addressed through program design, careful analysis of potential benefits from diffusion of solar resources, and coupling PV with demand response and energy storage. Based on these points, it is unreasonable to dismiss any capacity value to solar energy for a particular utility without considering these issues.

BEST PRACTICES IN VALUING NET ENERGY METERING

Given the recent efforts to value solar resources discussed in the "Relevant Studies" section, one can begin to see a relatively clear picture of the necessary inputs in a methodology to value solar resources.

Costs of Net Energy Metering from a Rate Impacts Perspective

On the cost side of the methodology, although the AE and APS studies did not attempt to develop a methodology for consideration of NEM costs, the two main inputs developed in D.09-08-026 for the RIM Test—NEM bill credits and program administration costs—are unsurprising and could be relatively noncontroversial if they are carefully developed.

As we have noted, careful calculation of NEM bill credits is important to avoid double counting of costs. CPUC D.09-08-026 suggests that costs should include reduced T&D and non-fuel generation revenues and lost potential revenues from a standby charge exemption. If NEM bill credits are determined by comparison of estimated bills before and after renewable resources are installed, "revenue losses" related to T&D charges and non-fuel generation revenues are already included. Moreover, customers who face demand charges based on maximum demand during the billing period could see little or no change in their demand charges, and thus would still be paying the T&D and non-fuel generation costs. For these reasons, inclusion of an additional input to measure T&D and non-fuel generation charges not collected by the utility due to NEM of solar and wind facilities is almost certainly double counting of this potential "lost revenue."

Depending on how standby charge tariffs are actually implemented by a particular utility, calculating the potential lost revenues from a standby charge exemption would double count T&D charges again. Inclusion of lost standby charges is also troublesome because standby charges have usually not been developed for intermittent DG resources and, therefore, are not based on the cost of serving these particular customers. To its credit, the E3 study considered this "lost revenue" in a sensitivity analysis, but did not consider it in the base case.

Caution concerning program administration costs is also warranted. While it might be intuitive to include the actual costs the utility estimates it has incurred in administering its NEM program, it is clear from the E3 study that critical review is necessary. As discussed in the prior section, self-reported administrative costs at PG&E were nearly quintuple the costs reported by SCE and SDG&E with no explanation for this disparity. While some variation in costs is reasonable, a cost spread of this magnitude should raise concern and be justified before inclusion in any cost-benefit analysis. Moreover, as utilities begin to implement billing system updates to handle smart meters, demand response/control functions, and other emerging policies, those systems should be designed to handle NEM more efficiently, and the incremental costs of NEM should decline to slightly more than zero.

Benefits of Net Energy Metering from a Rate Impacts Perspective

On the benefits side of the equation, each study discussed in this report finds that avoided T&D line losses, avoided capacity and energy purchase costs, and avoided T&D investment deferrals should be included as benefits (though the studies did not agree on how to account for the benefits). Inclusion of these benefits in a methodology to assess the possible rate impacts of NEM should be relatively noncontroversial given their consistent identification as benefits of customer investment in renewable energy resources. Avoided line losses stem from locating the generation source on site, which allows line losses due to transmission from distant generation sources to load to be almost completely avoided (there are very modest losses associated with excess generation stepping up to utility line voltage then back down when used nearby on the same circuit). Avoided capacity and energy purchase costs stem from the reduction in on-site customer load and export of excess energy. T&D investment deferrals stem from decreased customer load at the feeder, substation, and transmission levels, and can include deferrals of investment and postponing of investment in T&D upgrades. Care should be taken to ensure evaluation of T&D investment deferrals includes not only the deferral of capacity investment but also equipment and operations and maintenance, as both the APS study and D.09-08-026 recognize these value streams.

Moreover, both the AE study and the E3 study recognize that renewable resources can provide environmental benefits due to avoided emissions from non-renewable energy sources. These benefits are a direct consequence of the investment by customers in generation sources that emit few or no pollutants during their production of energy. While the AE study and E3 study took different approaches to valuing this benefit, given regulatory frameworks in place for the measurement of NO_x, $SO_{x,}$ and particulate matter, and efforts to regulate CO_2, assessment of the environmental benefits of renewable resources should not be excluded as a benefit. The ability to mitigate carbon regulatory risk is particularly valuable. The CPUC Self Generation Incentive Program Eight-Year Impact Evaluation Revised Final Report (Itron, Inc., 2009) finds that PV was able to mitigate approximately 0.58 tons CO_2 per MWh. Given forecasts of future carbon prices in the range of $15 to $45 per ton on a levelized basis between 2013 and 2030, this would suggest a value of approximately $9 to 26/MWh in avoided carbon on a levelized basis. (Schlissel et al., 2008)

Additionally, consideration should be given to the possible benefits customer-sited renewable resources will have on a utility's obligations to purchase renewable energy to meet state mandates as discussed in D.09-08-026. For example, because the California Renewable Portfolio Standard bases each utility's compliance obligation on retail sales, utilities will be able to avoid purchases of renewable generation they might have otherwise been required to purchase because customer-sited generation lowers a utility's retail sales. For this reason, D.09-08-026 finds that a typical avoided cost methodology might not fully capture the benefits of customer-sited renewable resources in avoiding renewable generation additions by utilities to meet their RPS obligations. States like Arizona and Colorado with similar RPS obligations should take care to ensure this benefit is appropriately assessed in their cost benefit methodology.

The AE study and D.09-08-026 also recognized that customer investment in renewable energy resources could have significant impacts on the natural gas market. The AE study identified the ability of PV to act as a hedge on natural gas price increases, and D.09-08-026 recognized that customer investment in renewable energy could decrease the demand for natural gas and thereby lower the market price of natural gas for all participants. Unfortunately, it concluded that the impact is too small and too difficult to discern at current DG penetration levels.

The conclusion that renewable energy has no impact on natural gas prices is not supported by research. A Lawrence Berkeley National Laboratory study (Wiser, Bolinger, & St. Clair, 2005) provides a detailed review of studies assessing this benefit. These studies show that the price impacts in terms of $/MWh of renewable energy additions are significant, ranging from $10/MWh to $65/MWh nationally. Regional impacts were also evaluated. For example, the Lawrence Berkeley study found the impact of approximately $5/MWh within California. Similarly, the price hedge for natural gas was estimated in the California Energy Commission's 2007 Integrated Energy Policy Report at approximately $12/MWh. Given many utilities' substantial and increasing reliance on natural gas fired generation and consumer level consumption of natural gas, natural gas price impacts should not be ignored when estimating the rate impacts of NEM. Each of these benefits are significant and well documented and, therefore, worthy of inclusion as a benefit of customer-sited investment in renewable energy.

Regarding reliability, D.09-08-026 addressed only one part of the likely benefit of DG and arbitrarily set the value of other reliability benefits at zero. The decision concluded that demand reductions due to DG resources are likely to lead to the same reliability benefits that result from energy efficiency measures and the existing methodology to calculate that impact should be used for the present time. However, it only acknowledged that DG has the potential to provide ancillary services and var support. This ability has been widely acknowledged for inverter-based systems, although output voltage is typically preset rather than being reactive to utility grid voltage, so the ability to provide support is not used at present. However, this ability is very likely to be tapped, at least for larger solar facilities, and could add significant value. Even more importantly, the AE study properly noted that DG has the potential to provide backup power to both critical need customers and typical utility customers. The AE study placed a very high value on this functionality and it seems that some estimate should be made of this value. D.09-08-026 simply set var support and backup power values at zero, but properly directed that those values should be estimated.

Based on the three solar valuation studies reported here, best practices in developing a methodology for evaluating the rate impacts of net metering counsel for including the inputs noted in Table 2.

TABLE 2

Necessary Costs and Benefits Inputs in a Methodology for Evaluating the Rate Impacts of Net Energy Metering

Benefits to the Utility	Costs to the Utility
Avoided Energy Purchases	NEM Bill Credits
Avoided T&D Line Losses	Program Administration
Avoided Capacity Purchases	
Avoided T&D Investments and O&M	
Environmental Benefits—NO_x, SO_x, PM, & CO_2	
Natural Gas Market Price Impacts	
Avoided RPS Generation Purchases	
Reliability Benefits	

CONCLUSION

To date, views concerning the possible rate impacts of NEM programs have driven many of the policy deviations from best practices in NEM in many states. However, very little rigorous analysis of the relative costs and benefits of NEM has been done. In reviewing the major net metering and PV cost-benefit studies performed to date, we identified the benefits noted at the end of the previous section as essential for inclusion in any study of the possible NEM rate impacts.

On the cost side of the analysis, the three studies provide guidance as well. The primary cost of NEM is the utility's lost revenue from utility ratepayers, equal to what ratepayers would have paid had NEM not been available. As the E3 study did, we recommend that the lost ratepayer revenue only focus on the bill impacts directly attributable to NEM (i.e. directly attributable to providing value to excess generation). The lost revenue due to NEM should not be based on all production from customer-sited generation, because a customer can install a system to offset their energy needs without an NEM program in place. While simplifying assumptions—that the amount of generation installed would not change or other measures would not be taken to store excess energy for later consumption, for example—are necessary, given the relatively small percentage of generation that is actually net metered, such simplifications seem reasonable.

In addition, utility administrative costs should be included, as discussed in the E3 study. However, the variance in administrative costs among the three California utilities surveyed indicates a need to review cost claims carefully. An assumption regarding future administrative cost reductions per kWh should be included to account for automation of processes. Other costs can be considered based on any unique features of a state's net metering program, but they should be carefully considered to ensure they actually stem from a state's decision to allow net metering versus a decision to allow customer-sited generation as a general matter.

E3's pioneering work quantifying the benefits and costs of California's NEM program highlights the fact that further research is necessary to arrive at consensus on the appropriate methodology for quantifying these benefits and costs. However, the inclusion of the benefits listed at the end of the prior section should be relatively noncontroversial in most instances. As noted earlier, the cost-benefit analysis is utility-specific, and some utilities may realize little benefit from one or more of the items noted in Table 2. A utility in a state without an RPS will not have any savings associated with avoided RPS purchases. A winter-peaking utility will not have a substantial capacity benefit.

Based on the review undertaken in this report, it would be difficult to conclude that nonparticipating customers subsidize demand-metered customers with NEM facilities. The cost to the utility of demand-metered customers deploying NEM is the loss of energy charges, but those energy charges are based on the variable costs that the utility avoids by not having to provide the energy that is instead generated on site. The administrative cost in the long run should drop to almost nothing per kWh, and the non-energy benefits discussed here will still be provided. It appears that demand-metered customers with NEM facilities will typically provide a net benefit to nonparticipating customers.

For customers with bundled rates, such as residential customers, whether or not there is a net benefit will depend on utility-specific costs and benefits.

RECOMMENDATIONS

We recommend that utility regulators wishing to determine the NEM rate impact for specific utilities use the guidelines provided in this report. In particular, we recommend that:

- Studies comparing the costs and benefits of NEM include the costs and benefit inputs identified in Table 2 above.
- As part of this effort, none of the benefits identified in Table 2 should arbitrarily be set to zero based on unsupported assumptions.
- Capacity benefits associated with deferral of utility generation and T&D facilities should be modeled under a long-term framework to ensure that the value of PV to defer these resources under a long-term planning framework is properly captured.
- Assessment of the costs and benefits of net metering should be based only on exported energy, not the entire production of the facility.
- Program administrative costs should be based on a long-term assessment of costs based on the expectation that updating utility billing software to accommodate and support grid-modernization efforts, which include net metering, will be necessary.

At the earliest stages of a NEM program, the cost of such studies may be greater than any net costs or net benefits themselves, and regulators may understandably be hesitant to undertake studies prior to significant NEM deployment. The results discussed in this report should give regulators confidence that rate impacts at the earliest stages will be negligible and need not be a concern that leads to restrictive NEM policy.

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Appendix A

Summary of Costs and Benefits Inputs Used in Three Solar Valuation Studies

	Austin Energy Study	APS Study	CPUC E3 NEM Study
BENEFITS			
Energy production value	X	X	X
Generation capacity value	X	X	X
T&D deferrals	X	X	X
Reduced transformer losses	X	X	X
Reduced line losses	X	X	X
Environmental benefits	X		
Natural gas price hedge*	X	X	
Blackout prevention*	X		
Emergency utility dispatch*	X		
Managing load uncertainty*	X		
Retail price hedge*	X		
Reactive power control*	X		
Reduced distribution system size		X	
Avoided fixed operating costs		X	
Avoided environmental compliance			X
Avoided ancillary services			X
COSTS			
Net metering bill credits			X
Program administration**			X
Reduced standby charge revenue***			X
Costs of interconnection not charged***			X

* These benefits were not quantified in the Austin study. The study found that the benefits were real and quantifiable, but there was insufficient data to assign them a value for Austin Energy.

** Because of data problems with utility reported billing costs, these costs were also included in a sensitivity analysis.

*** These benefits were included as sensitivity analysis.

ACRONYMS

AE	Austin Energy
APS	Arizona Public Service
CPUC	California Public Utilities Commission
D.	decision
DG	distributed generation
IOU	investor owned utility
kW	kilowatt
kWh	kilowatt-hour
MPR	market price referent
MW	megawatt
NEM	net energy metering
NNEC	Network for New Energy Choices
PG&E	Pacific Gas & Electric
PA	program administrator
PV	photovoltaic
R.	rulemaking
RIM	ratepayer impact
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPM	California's Standard Practice Manual
TRC	total resource cost
T&D	transmission and distribution
var	volt-ampere reactive

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LETTER

Exploring the market for third-party-owned residential photovoltaic systems: insights from lease and power-purchase agreement contract structures and costs in California

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Abstract

Over the past several years, third-party-ownership (TPO) structures for residential photovoltaic (PV) systems have become the predominant ownership model in the US residential market. Under a TPO contract, the PV system host typically makes payments to the third-party owner of the system. Anecdotal evidence suggests that the total TPO contract payments made by the customer can differ significantly from payments in which the system host directly purchases the system. Furthermore, payments can vary depending on TPO contract structure. To date, a paucity of data on TPO contracts has precluded studies evaluating trends in TPO contract cost. This study relies on a sample of 1113 contracts for residential PV systems installed in 2010–2012 under the California Solar Initiative to evaluate how the timing of payments under a TPO contract impacts the ultimate cost of the system to the customer. Furthermore, we evaluate how the total cost of TPO systems to customers has changed through time, and the degree to which contract costs have tracked trends in the installed costs of a PV system. We find that the structure of the contract and the timing of the payments have financial implications for the customer: (1) power-purchase contracts, on average, cost more than leases, (2) no-money-down contracts are more costly than prepaid contracts, assuming a customer's discount rate is lower than 17% and (3) contracts that include escalator clauses cost more, for both power-purchase agreements and leases, at most plausible discount rates. In addition, all contract costs exhibit a wide range, and do not parallel trends in installed costs over time.

Introduction

Residential solar photovoltaic (PV) systems constituted roughly one quarter of the PV capacity installed in the United States in 2013—an estimated 792 MW (GTM Research 2013). While the PV market has been growing rapidly, PV still makes up a very small portion of the total US energy mix. As costs continue to decline and the industry continues to grow, PV could begin to make a substantial contribution to the US energy mix over the next couple of decades (DOE 2012). PV costs have witnessed steady declines over the past several decades, and in the past four years, have nearly halved (Feldman and Friedman 2013). At the same time, PV incentives—including the federal investment tax credit (ITC) and various state, municipal, and utility rebates and tax credits—have substantially reduced the capital requirements to install solar. However, achieving grid parity (the ability to generate electricity at a cost that is less than or equal to the price of purchasing power from the electricity grid) will require additional cost reductions, and these cost reductions will need to be passed on to consumers.

The use of third-party-ownership (TPO) structures for PV has increased considerably over the past several years —from an estimated 10–20% in large US markets in 2009, to an estimated 65% of the US market in 2013 (GTM Research 2013, GTM Research 2014). TPO provides an attractive alternative for consumers who either do not want to assume risks associated with ownership or prefer a low money down payment option. Further, a TPO structure can make financial sense due to the challenges individual homeowners face in monetizing the ITC and modified accelerated cost recovery system (MACRs) depreciation[1]. Under a TPO contract, the contract type and payment structure between the solar customer (homeowner) and the system owner (solar integrator or third-party financer) can take the contractual form of a solar lease or a solar power-purchase agreement (PPA). In a solar lease, the customer pays a specified amount (agreed upon at the outset of the contract) every month, regardless of the system's energy production. In a solar PPA, the customer pays a specified amount per kilowatt-hour (kWh) of generation, so the amount paid varies monthly as a function of generation. Regardless of the type of contract (lease or PPA), customers typically pay a one-time, upfront down payment and monthly payments. The monthly payments can be flat, but in some cases, monthly payments may escalate at a flat rate through time. As a result, the timing of the payments by the homeowner varies by the magnitude of the down payment and monthly payments and the rate at which the payments escalate. Often the installer will provide the homeowner a menu of contract options by varying these parameters, with implied financial tradeoffs. Contract prices can be objectively compared and evaluated by aggregating the sum of down payments and the monthly payments over the duration of the contract and discounting. This total contract price—the real (i.e. 2012 dollars) out-of-pocket cost the customer is contractually obligated to pay—is the key economic measure for residential customers evaluating different TPO PV lease/PPA contracts.

While several current sources track installed PV prices via incentive program data and other market data sources (GTM Research 2013, Barbose *et al* 2014), there is little data on the out-of-pocket cost to the customer over the duration of the contract, which will be substantially reduced by available incentives. Further, while a few studies have evaluated the financial implications of buying versus leasing solar (Rai and Sigrin (2013), Navigant Consulting 2014), to date, no study has focused exclusively on comparing contract costs across the myriad TPO options offered to customers. In both of the above studies, results suggested that leasing provided a higher net present value than ownership—though the difference was more drastic in Rai and Sigrin (2013).

In this study, we use third-party contract data from the California Solar Initiative (CSI) to examine California's residential TPO market during 2010–2012[2]. We use a sample of 1113 contracts to evaluate how TPO contract structures vary and how this translates into a final TPO contract price. We use this data to evaluate the effect of contract structure, magnitude of down payment, and escalation clauses on the total contract price.

The remainder of this article is organized as follows. First, we discuss the study data, our sampling procedure and the method to convert contract terms into a total contract price (2012 dollars). Second, we evaluate contract characteristics: distribution of lease versus PPA and various payment structures (timing of payments and existence of escalation rates). Third, we evaluate TPO contract prices according to the structure and terms in the contract, as well as trends over time and by size. Finally, we assess whether customers appear to be selecting optimal contract structures.

Methodology

The California Public Utilities Commission (CPUC) oversees the CSI, a solar incentive program available to customers of the state's three investor-owned utilities: Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The CSI has a $2.4 billion budget to stimulate the deployment of approximately 1940 MW of new solar capacity between 2007 and 2016 via solar rebates for residential, commercial, and utility-scale systems, including systems for low-income residents and multifamily affordable housing. To drive continual PV price reductions, the CSI incentive amount declines incrementally as the program reaches specific levels of cumulative installed capacity (separately specified in each of the three utility areas).

In this analysis, we focus on the residential sector during 2010–2012. During this period, systems in the CSI database represented about 45% of the residential PV installed nationwide (GTM Research 2013, California Solar Statistics 2014). The initial residential customer rebate was $2.50/W in January 2007, and this declined to a final rebate of $0.10/W in 2013[3]. During 2010–2012, incentives for residential systems ranged from roughly $1.50/W–$0.20/W, depending on the utility.

The CPUC requires incentive applicants to submit the installed system cost and documentation supporting that cost. For TPO systems, the CPUC requires installers to submit signed system contracts, which in many cases include the terms of the lease arrangement between the solar customer and the system owner.

The CPUC provided NREL with access to more than 50 000 residential third-party contracts signed

[1] MACRS is the tax depreciation system that allows businesses to recover the cost basis of an asset via annual tax deductions for depreciation, for commercial entities. In contrast to straight-line depreciation, where an asset is depreciated in equal increments annual over the useful life of the asset, MACRS in the case of a solar asset specifies the following 5-year depreciation schedule (20%, 32%, 19.2%, 11.52%, 11.52%, and 5.76%).

[2] Over this period, residential third party ownership in California increased from 22% to 69% of new installations (CSI 2014).

[3] The CSI program pays an expected performance-based buydown (EPBB)—a capacity-based incentive that is adjusted based on expected system performance that considers major design characteristics of the system, such as panel type, installation tilt, shading, orientation, and solar insolation available by location. By the end of 2013, CSI rebates had been exhausted in PG&E territory.

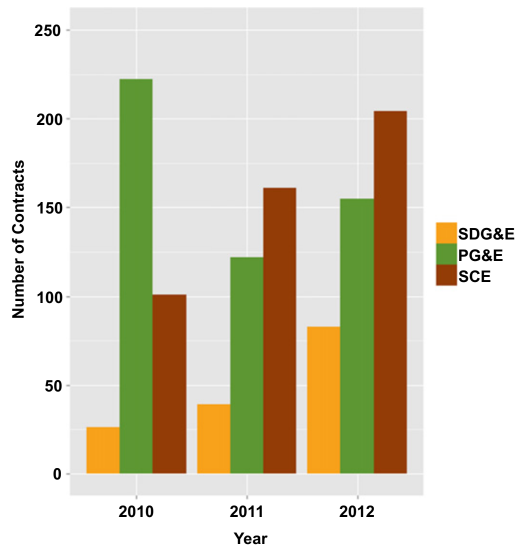


Figure 1. Number of TPO contracts in sample by year and utility.

during 2010–2012[4]. We sampled 2400 residential contracts, with a mean system size of 6.04 W_{DC}[5]. To maximize our ability to make inferences about changes over time, we stratified our sample by quarter, selecting 200 contracts for each quarter from the first quarter of 2010 to the last quarter of 2012, based on the 'completed date' as recorded in the CSI database[6]. This resulted in a sample of 1113 contracts with usable data (the remaining contracts simply provide the signed contract, without down payments or monthly payments), from 162 installers. The distribution of the contracts that did not include usable price terms closely matched the distribution of the contracts with usable price terms by utility and quarter, reducing concerns about selection bias. As a result, this sample can be considered representative of the geography and installation timeframe of the IOUs in California. The distribution of the final dataset by year and utility is displayed in figure 1.

To evaluate contract prices across leases and PPAs with varying payment horizons and escalators, we rely on a discounted cash flow (DCF) methodology. The DCF aggregates all payments, present and future, to assign a total present value to each contract in 2012 dollars, which enables us to compare contracts with different structures. For the rest of the article, we refer to this figure as the 'real contract price' or the 'TPO contract price'. This implies the real (2012 dollars) price of a lease or PPA contract to the homeowner. Future payments are discounted according to a selected discount rate intended to reflect the 'typical' consumer's tradeoff between present and future expenditures. In reality, each consumer will have a unique discount rate which will vary as a function of the opportunity cost of investing capital—i.e., what rate of return a consumer can expect from investing their money elsewhere. The cost of homeowner borrowing provides a reasonable proxy, which can range from low-rate home-equity lines of credit, to high-rate credit cards. However, additional factors present in a new market such as informational deficits, outsized perceptions of risk, aversion to sizable investments and other factors could increase a consumer's discount rate. Further, research has found that discount rates for energy conservation investments are higher than for other investment decisions (Meier and Whittier 1983, Train 1985), perhaps because of higher uncertainty over future conservation savings (Hassett and Metcalft 1993). Less research has evaluated the discount rate for green energy generation investments, but there may be a similar degree of uncertainty. Rai and Sigrin (2013) found implied discount rates as high as 60% for PV adopters in Texas.

Owing to the wide range of theoretically plausible discount rates, we evaluate contracts over a range of discount rates when possible. For figures or calculations relying on one discount rate, we use 7% as a default nominal discount rate. Equation (1) presents the formula used to calculate the price of each contract.

$$\begin{aligned}&\text{Real contract price}(\$2012)_i\\&\quad= \text{Upfront payment}\\&\qquad+\sum_{y=1}^{t}\left(\left[\text{monthly payment}^*(1+e)^{y}{}^*12\right]/\right.\\&\qquad\left.\left[(1+d)^{y-1}\right]\right),\end{aligned} \tag{1}$$

where i is the individual contract, t is the term length, y is the contract year, e is the escalation rate, d is the discount rate.

In the case of a PPA, the monthly payment is estimated based on assessed average monthly production stipulated in the contract[7]. We assume system production declines of 0.05% per year (Jordan and Kurtz 2011) and calculate the estimated monthly payment as follows:

$$\begin{aligned}&\text{Estimated monthly payment}\\&\quad= \text{estimated monthly production} \times (0.995)^{y-1}\\&\qquad\times \text{PPA rate}.\end{aligned} \tag{2}$$

Based on these calculations, we assign a real contract price to each contract.

[4] The CPUC only began storing digital versions of contracts beginning in 2010, so contract data were not readily available for previous years.

[5] All system sizes are reported in Watts-direct current.

[6] The 'completed date' is the date when the final incentive check was created and sent to the payee. This date may be several months after the contract terms were quoted to the customer.

[7] Companies likely rely on varying methods to estimate the average monthly production. We have no way to validate estimated monthly production or evaluate whether estimates are biased upwards or downwards as this depends on exact location, system design parameters, roof features and shading.

Table 1. Number of TPO contracts by year and type.

	2010	2011	2012
Lease	236	239	299
PPA	113	83	143

Results

Contract-type trends

Within our sample, nearly 69% of third-party contracts were structured as leases, with the remaining structured as PPAs (table 1). This proportion does not change substantially from 2010 to 2012. In our sample, most installers and integrators offered one structure exclusively (or nearly exclusively), although 10 of the 162 installers in our sample offered both leases and PPAs.

Whether a lease or a PPA, some contracts included an escalator clause, in which the base payment escalates at a given rate annually. Escalators are often included to allow revenue to keep pace with inflation[8]. In our sample, PPAs more consistently contained escalator clauses; 53% included an escalator of 3.0% (the most common level) or 3.9% per year. On the other hand, most leases in our sample data did not contain an escalator clause; among those that did, most had a relatively high escalator of 3.9% per year (figure 2). A smaller proportion of leases included escalators in 2012 than in 2010 or 2011, while the proportion of PPAs including escalators increased during our study period.

Contracts also varied in the timing of payments. The amount customers paid up front varied from zero (no-money-down) to the complete contract value (prepaid contract). Some contracts required partial payment up front, with the remaining contract price paid over time. With few exceptions, customers signed 20 year contracts.

Figure 2 shows the payment timing by contract type and year. The timing of PPA payments was weighted more toward the future compared with the timing of lease payments during each of the three years studied, with most PPAs structured as no-money-down contracts. However, the proportion of no-money-down leases increased substantially over the period. It is unclear whether this shift resulted from customer preferences or financer/integrator preferences.

Overall, the lease data suggests consolidation of preferences over time, with a trend towards an increasing percentage of no-money-down lease contracts. A recent trend towards securitization of solar leases and PPAs may play a role in this shift as a contract that is fully prepaid cannot be securitized. However, without additional data, it is not clear whether this shift is a result of customer preferences or financer/integrator preferences.

[8] Nationally, nominal residential electricity prices, on average, have increased by 2.01% annually in the last 20 years (U.S. Energy Information Administration 2011) and are forecasted to increase, on average, 2.20% annually from 2014–2040 (U.S. Energy Information Administration 2014).

Contract price analysis

In this section, we evaluate the full price of the TPO system to the end-consumer based on aggregating down payments and monthly payments from each contract to derive a real contract price. We provide an overview of the distribution of these prices, evaluating the value proposition provided by: (1) PPAs versus leases, (2) contracts with varying levels of upfront payments, and (3) contracts with and without escalators. Given that discount rates vary among consumers, we evaluate the contract price over discount rates of 0%–20%. Next, we evaluate effects of system installation year and system capacity on TPO contract price.

Impact of contract structure on contract price

Figure 4 shows the variation in contract price over the range of contracts sampled, assuming a 7% real discount rate. Both leases and PPAs exhibit a wide range. The mean contract price is $3.04/W for leases and $4.26/W for PPAs, with standard deviations of $1.28 and $1.08, respectively.

Figure 5 provides the distribution based on monthly lease payments per kilowatt and PPA rates per kilowatt-hour in order to provide a metric more comparable to terms found in TPO contracts. This is illustrated for no-money down contracts only. Monthly payments to lease a PV system range from $12/kW to $51/kW per month (sample mean $24.30/kW per month), and PPA rates range from $0.12/kWh to $0.35/kWh (sample mean $0.23/kWh).

PPA versus lease

Figure 6 illustrates the mean contract price, as well as the distribution of prices, for contracts with differing payment schedules. PPAs are consistently higher priced than leases, though much of this difference may be explained by the structure of the contracts; as a sample, leases are comprised of many more prepaid contracts. When comparing across similar payment structures, the difference between PPAs and leases declines as the amount of down payment declines. For the only category in which payment timing is exactly the same-0 down—the difference between PPAs and leases declines to $0.52/W. Price differences between PPAs and leases, in all cases, are statistically significant. In the discussion section, we explore several hypotheses for this persistent pricing difference.

Contract payment timing: 'no-money-down' versus prepaid

Figure 7 illustrates the price differences in contract payment timing—focusing on leasing, which provides

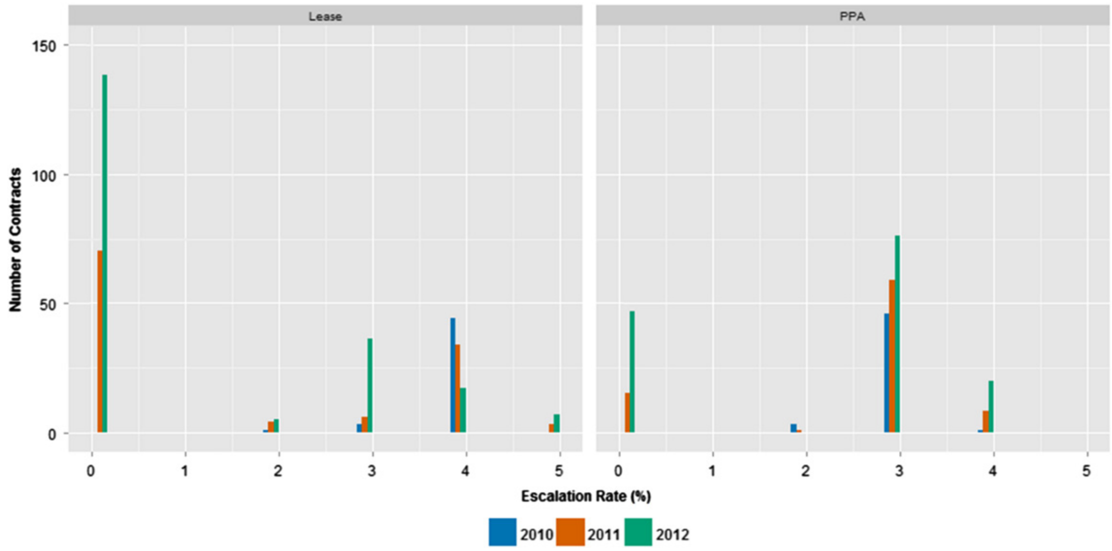


Figure 2. Escalation rate by contract type and year.

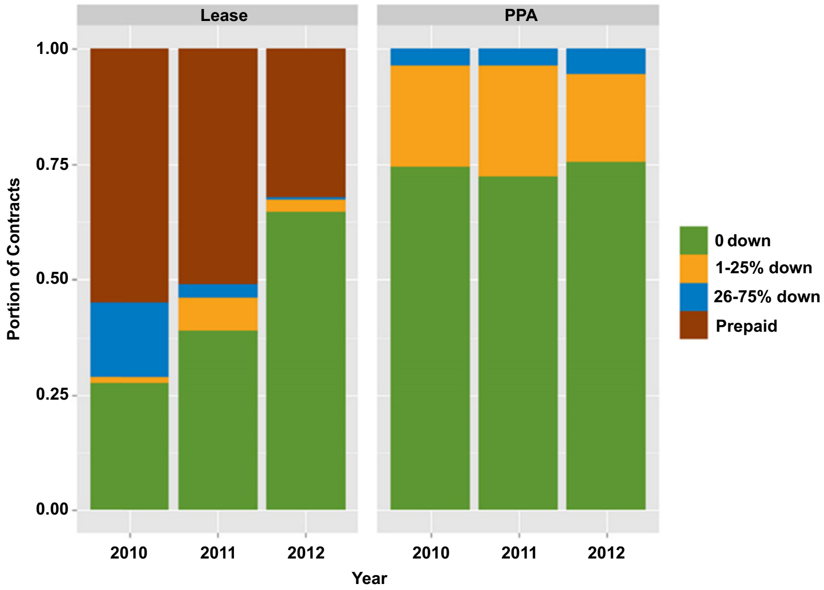


Figure 3. Contract payment schedule by contract type and year.

examples of both 'no money down' and fully prepaid contracts, at varying discount rates. As expected, no-money-down contracts cost more over the life of the contract in the lower range of discount rates. The two contract structures equate in price at a discount rate of approximately 17% as illustrated in figure 7.

These data suggest that, on average, a prepaid contract is financially preferable to a no-money-down contract if the consumer's expected rate of return on a competing investment is equal to or lower than 17%[9].

[9] This omits the additional option of paying a portion of the contract upfront and paying the remainder through monthly payments over a 20-year period. However, focusing on these two categories enables comparison across contracts that have identical payment timing within the two categories—payments are either fully paid upfront, or paid in equal increments over (typically) 20 years.

Escalators

As illustrated in figure 3, contracts commonly include payment escalators, although escalators are more common in PPAs than in leases. Figure 8 illustrates the real contract price of PPAs and leases with and without escalators[10]. It suggests that a contract with an escalator costs a consumer more than a contract without an escalator at nearly all plausible discount rates. At a discount rate just under 16%, leases with escalators approximately equate with leases without escalators. On average, PPAs with escalator clauses, at

[10] We combine all contracts with escalators over 2.9% and exclude seven contracts with 1.9% escalators. For both leases and PPAs, this results in a blending of escalation rates, although 94% of escalation rates are 3.9% and 2.9%.

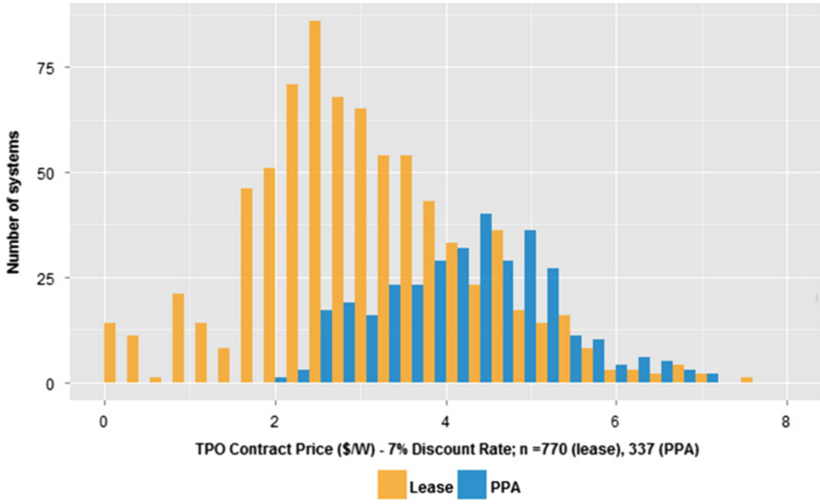


Figure 4. Distribution of contract prices for PPAs and leases (assuming a 7% discount rate).

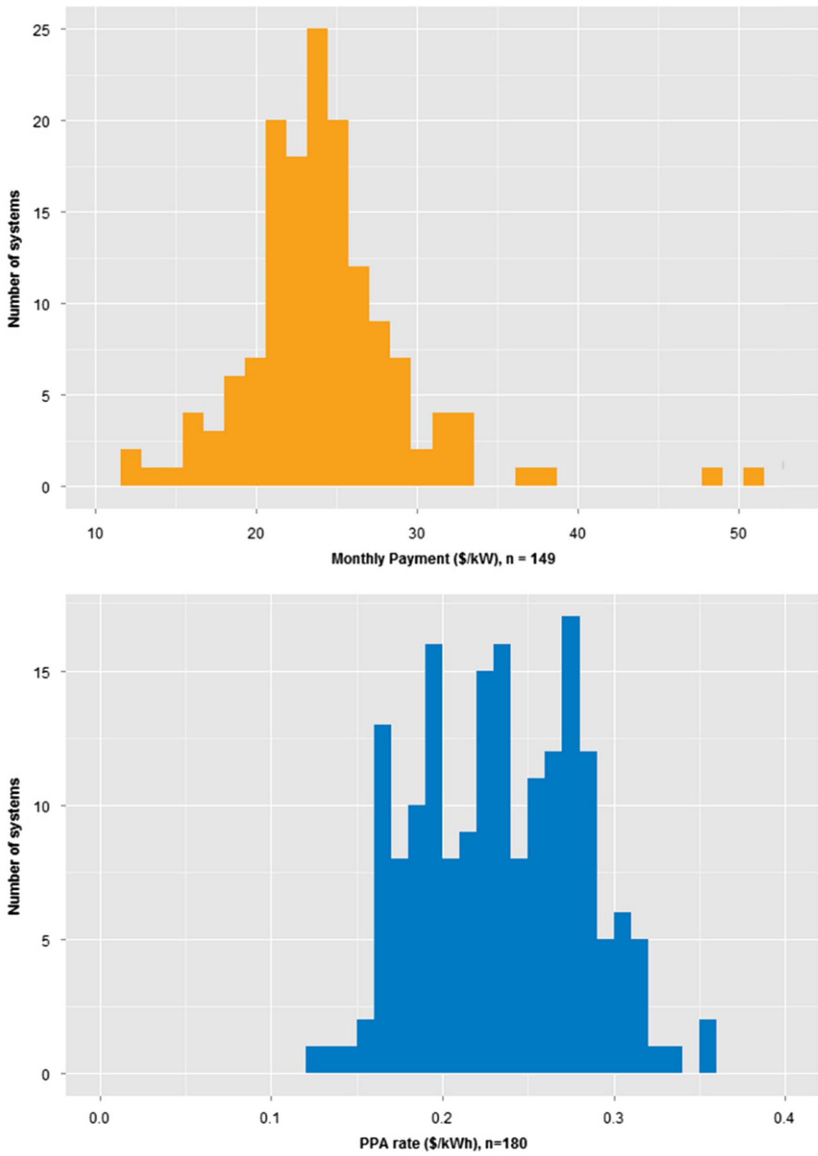
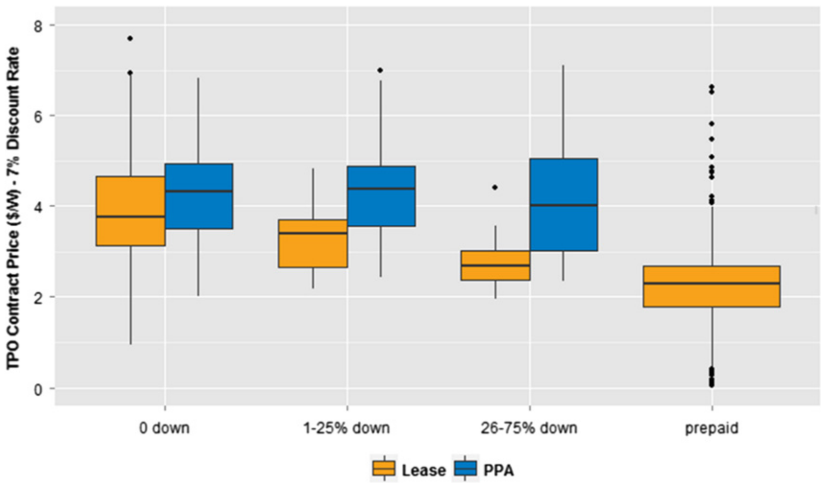


Figure 5. Distribution of monthly lease payments (top) and PPA rates (bottom); no-money down contracts.



	Lease	PPA
	Mean Contract Price ($/W) and observations	
0 down	$3.79 (n=351)	$4.31 (n=251)
1-25% down	$3.39 (n=27)	$4.38 (n=71)
26-75% down	$2.70 (n=46)	$4.01 (n=15)
prepaid	$2.30 (n=346)	NA (n=0)
All contracts	$3.04 (n=770)	$4.27 (n=337)

Figure 6. Real contract price by contract type, discount rate, and payment structure.

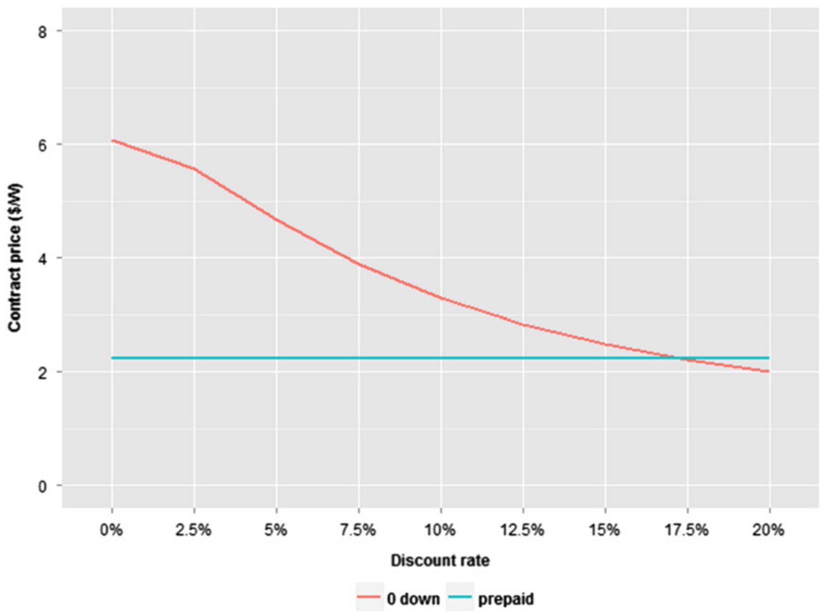


Figure 7. Present-value lease price by payment structure and discount rate.

every discount rate, cost more than PPAs without escalator clauses.

Contract price by reported price, installation year, and system capacity

In this section, we evaluate contract prices in relation to reported PV system prices, year of system installation, and system capacity.

As installed costs decline, we would expect installers to pass a portion of the cost declines along to TPO contracts and reduce prices. Installed prices reported to the CSI program declined by roughly $2.00/W during 2010–2012. Over this same period, the CSI incentive declined by $0.87/W, from a median of $2.40/W in the first quarter of 2010 to $1.53/W in the last quarter of 2012. That is, reported prices declined more rapidly than did incentives. However, the average price of contracts changed less over this period, with both lease and PPA prices *increasing* in 2010–2011, and then PPA prices decreasing in 2012,

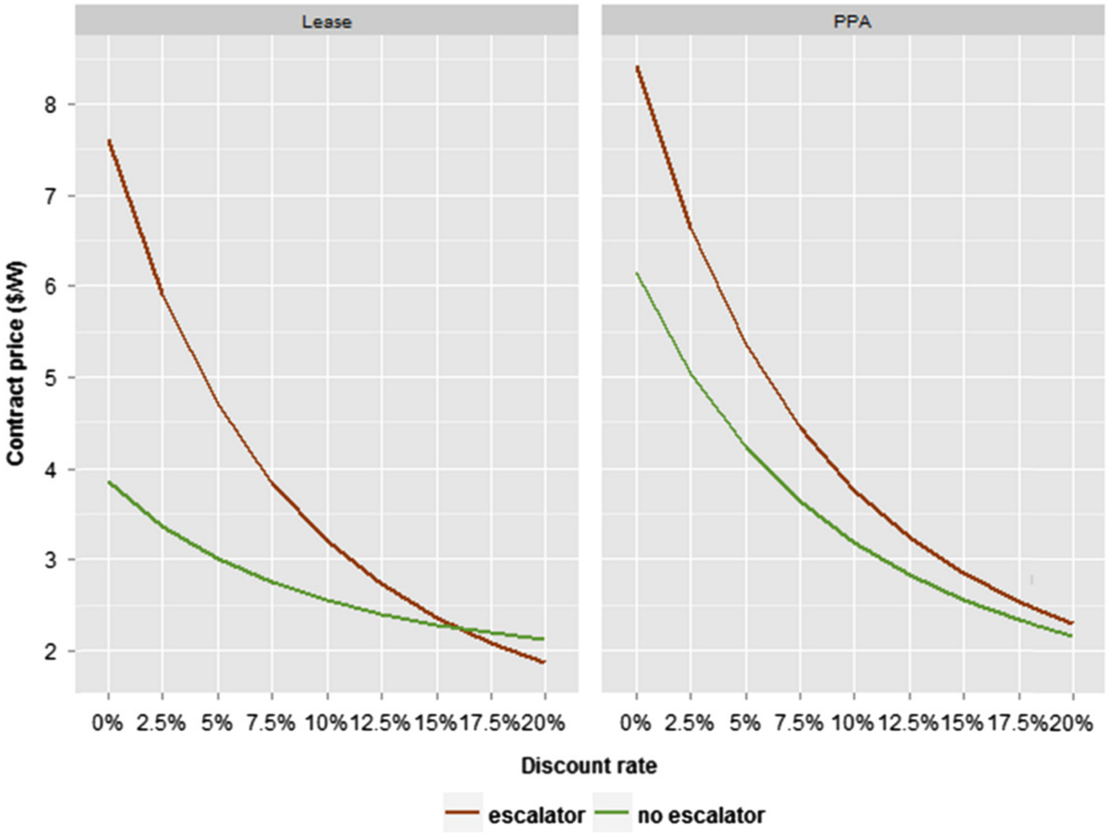


Figure 8. Real contract price by discount rate, contract type, and escalator.

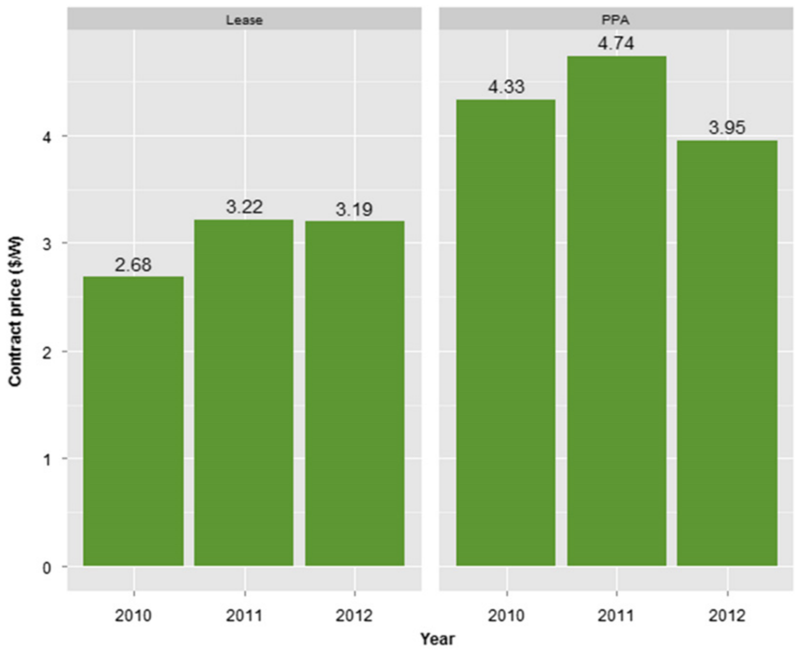


Figure 9. Real contract price (mean) by year for leases (left) and PPAs (right), 7% discount rate.

while lease prices remained flat (figure 9)[11]. While difficult to isolate the cause of these changes without further data, this suggests that factors beyond the installed cost of systems drive trends in contract prices. This may reflect costs associated with the TPO model (acquiring financing, operations and maintenance, system monitoring), outlined in Feldman

[11] The increase in lease prices between 2010 and 2011 was found to be statistically significant at <1%, however the difference between lease prices in 2011 and 2012 was statistically insignificant. The increase and subsequent decrease in PPA prices in 2010, 2011 and 2011, 2012, respectively, are both significant at <1%.

and Friedman (2013), but also likely reflects consumer demand dynamics.

We would also expect to observe economies of scale based on system size in contract prices, because larger systems enable the installer to spread certain fixed or lumpy costs (system permitting, business overhead) over a larger installed system. Barbose *et al* (2014) found that the mean installed reported price, nationwide, for systems of 5–10 kW was approximately \$0.50/W lower than for systems of 2–5 kW in 2012[12]. Similarly, Davidson and Steinberg (2013) found a difference of approximately \$0.70/W, focusing on host-owned systems in California. Our data suggests that contract prices (for leases and PPAs) are higher for small systems (2–5 kW)—statistically significant at <5%, but exhibit no statistically significant difference in price between 5 and 15 kW (figure 10)[13]. There is no notable difference in the distribution of leases and PPAs across the difference size categories—70–75% are between 2 and 7 kW, and ~25% are 7–10 kW for both contract types,

Each of these systems is associated with a corollary publically-reported price. While in the case of host-owned systems, this represents the transaction between the system owner (homeowner) and the installer, in the case of TPO systems, this can represent either the appraised value of the system (by an independent third-party), or the price of an intermediate transaction between the installer and the financer. We would expect reported prices to be higher than the end customers' price as lease/PPA prices net incentives (in this case, the CSI rebate, ITC and MACRS depreciation). The reported prices for the systems in our sample exhibit a wide range from \$5.10/W to \$7.98 \$/W (20th and 80th percentile), with a mean of \$6.38/W. Figure 11 illustrates the distribution of differences between prices reported to the CSI and the calculated contract price for each system in our sample. This illustrates a \$2.96/W difference, on average, though the distribution shows two peaks.While reported price and contract price are distinct metrics, they may be assumed to be strongly correlated given that they represent different transactions for the same system—but this is not the case in our sample. The Pearson correlation coefficient between the two metrics is 0.08.

Discussion and implications

The real contract price (discounted sum of all lease/PPA payments) of both leases and PPAs exhibit a rage of over \$7/W based on a 7% discount rate. Our findings suggest that differences in total contract price are partially driven by differences in contract structure and timing, although we note that a number of other factors may be contributing to these differences as well, not least of which is consumer willingness to pay, and price discrimination by installers.

First, we find that, on average, PPAs cost \$1.23/W more than leases assuming a 7% real discount rate—though this difference declines to \$0.52 when evaluating no-money-down contracts (the majority for the most recent year of data)[14]. Absent differences in payment timing, a number of potential reasons explain why a contract structured as a PPA costs the customer more than a lease, on average. The following are three potential factors:

(a) A PPA, relative to a lease implies two risks to the owner/financer: (1) seasonal revenue difference—lower revenue in winter months when systems are producing less; (2) ongoing production variance. The downside risk of system underproduction (due to cloud cover, low insolation, soiling, malfunction) is transferred from the host to the owner/financer since the host pays only for actual electricity generated. The owner/financer can be expected to be compensated for bearing this risk, and the host customer may be willing to pay a premium to reduce this risk. Further, PPAs typically stipulate a payment cap, regardless of production. The potential to receive 'free' energy if the system produces more than estimated in the contract may increase the host customer's perceived value.

(b) Due to this payment cap, system production may be overestimated (in the contracts) by the owner/financer in order to minimize the likelihood that 'free' energy is delivered to the customer above the cap. Estimates of monthly payments rely on production estimates, so if a system produces less than the amount estimated in the contract, the customer ultimately pays less than anticipated. Without system design parameters, there is no way to validate estimates of system production.

(c) Most companies that provided PPAs did not provide leases, so this could reflect installer-specific practices.

Second, we find that prepaid contracts, on average, cost less than no-money-down contracts at discount rates up to 17%—suggesting that consumers may have very high discount rates. This figure is consistent with the low end of implied discount rates for PV lessors in Rai and Sigrin (2013). Further, since a prepaid contract is analogous to purchasing a system in terms of payment timing, insights can be applied from research on the financial tradeoffs of buying versus leasing in other

[12] This excluded systems categorized as providing an appraised value, rather than a system cost.

[13] For this study, we did not have access to detailed system cost information that would fully characterize the costs of a given system. The cost—particularly the labor requirements—will vary by house based on factors such as system layout and roof structure/obstructions.

[14] This difference is found to be statistically significant at >0.1%.

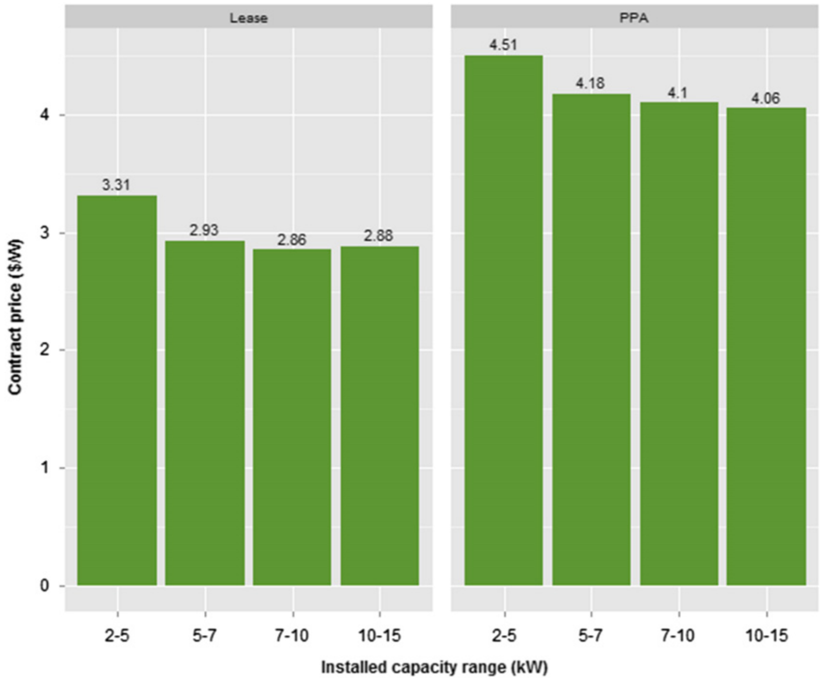


Figure 10. Real contract price (mean) by system capacity for leases (left) and PPAs (right), 7% discount rate.

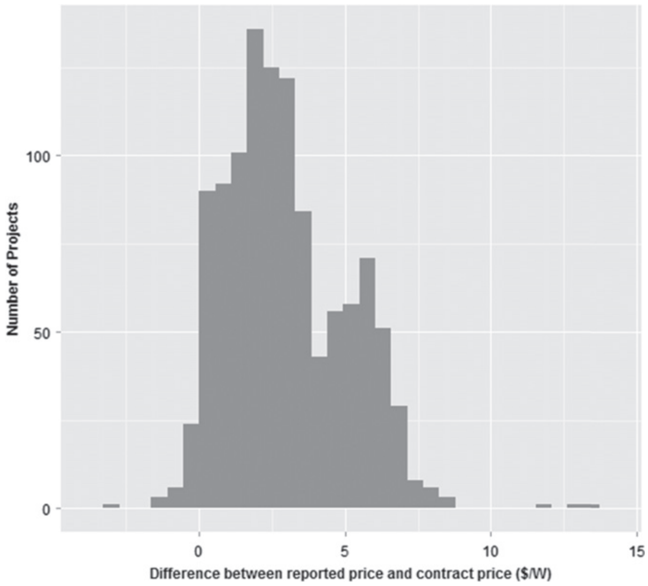


Figure 11. Difference between CSI-reported installed price and calculated contract price, 7% discount rate.

consumer durables. Typically, financial analysis suggests that monthly leasing provides a greater benefit than prepaying a lease (assuming this is analogous to a purchase) when the discount rate that equates the two cash flows is less than the after-tax rate of return that the lessee can obtain on invested capital. Although the implied discount rate in consumer durable markets sometimes appears high, this may be attributed to other consumer values. For example, Dasgupta *et al* (2007) and Nunnally and Plath (1989) found that the implied discount rate for automobile leases were higher than available returns on capital, but Mannering identified frequency of vehicle upgrades as a consumer value that could explain this consumer behavior[15].

However, analogies to other consumer durables are limited in that the adoption decision of a typical consumer durable does not directly offset another

15 It is possible that some customers may not have the access to inexpensive capital to prepay a lease (savings, home equity lines of credit, etc)—but unlikely, as financers typically require a FICO score >700 to qualify for a lease or a PPA.

substantial household cost. Given a sufficiently high monthly savings on electricity costs, a homeowner may prefer to save their cash or divert it to other purposes, and opt for a monthly lease/PPA, foregoing the relatively higher return by not prepaying the lease[16].

Third, we find that changes in key drivers of installed costs do not necessarily impact the price of a TPO contract to the customer. This is reflected in the fact that TPO contract prices do not consistently decline over the period of analysis, though we do see modest evidence of economies of scale based on system size. In the absence of sufficiently informed customers, firms can price discriminate, selling systems above their marginal cost at prices influenced by consumers' willingness-to-pay. A consumer's willingness-to-pay for PV is, in part, a function of the savings produced by offsetting purchased electricity. However, without access to pre-solar electric bills, we cannot test whether this drives contract prices. As a relatively nascent market, several factors likely preclude competitive TPO pricing, including asymmetric information regarding attributes of PV systems and high search and cognitive costs to seek and compare quotes.

Conclusion

This analysis indicates that the choice of contract type and payment structure may have implications for the total cost to the customer over the lifetime of the contract. Our sample data suggest the following findings:

1. PPA contracts appear to cost more than leases, and this trend persists when contracts are categorized by the amount of upfront payment. This could be driven by several factors, including higher perceived value/lower risk of the PPA contract structure to the customer, company-specific pricing for companies that only offer PPAs, and/or overestimating system production resulting in higher *apparent* PPA payments per watt[17].
2. Delaying lease payment increases the total price to the customer at most plausible discount rates. Specifically, no-money-down contracts are more costly than pre-paid lease contracts assuming a customer's rate of return is lower than 17%.
3. Contracts that include escalator clauses cost more over the lifetime of the contract, for both PPAs and leases, at most plausible discount rates.

[16] However, in these cases, assuming a homeowner can access a sufficiently low interest rate home equity loan, it would be advantageous to prepay a system with a home equity loan.

[17] PPA contract costs are estimated based on assumed production —and may be ultimately be higher or lower depending on realized system production.

Variation in contract prices across different contract structures suggests insufficient customer information and/or very strong customer preferences for certain contract structures. There are likely high search costs and high cognitive costs involved in obtaining multiple bids and comparing bids that might vary by factors such as system size/configuration and perceived quality in addition to variations in contract structure. Future research could better evaluate the degree to which customers are electing the optimal choice by evaluating quotes to the same homeowner, and accounting for the full economic value of the system by understanding a homeowner's pre-solar electricity expenditure.

However, as the market continues to develop, increased competition, particularly in regions with an active solar market, will likely put downward pressure on TPO prices. Tools and resources that facilitate sharing contract bids and/ or comparing multiple bids can reduce information asymmetry by reducing the search cost for consumers and providing data on prices for similarly sized systems.

Our study indicates that, while installed PV costs have declined rapidly, the real contract price to the customer has remained largely unchanged. Appealing to a broader market, particularly homeowners with lower electricity expenditure and/or in areas with less abundant sunlight may require offering lower-cost contracts to homeowners.

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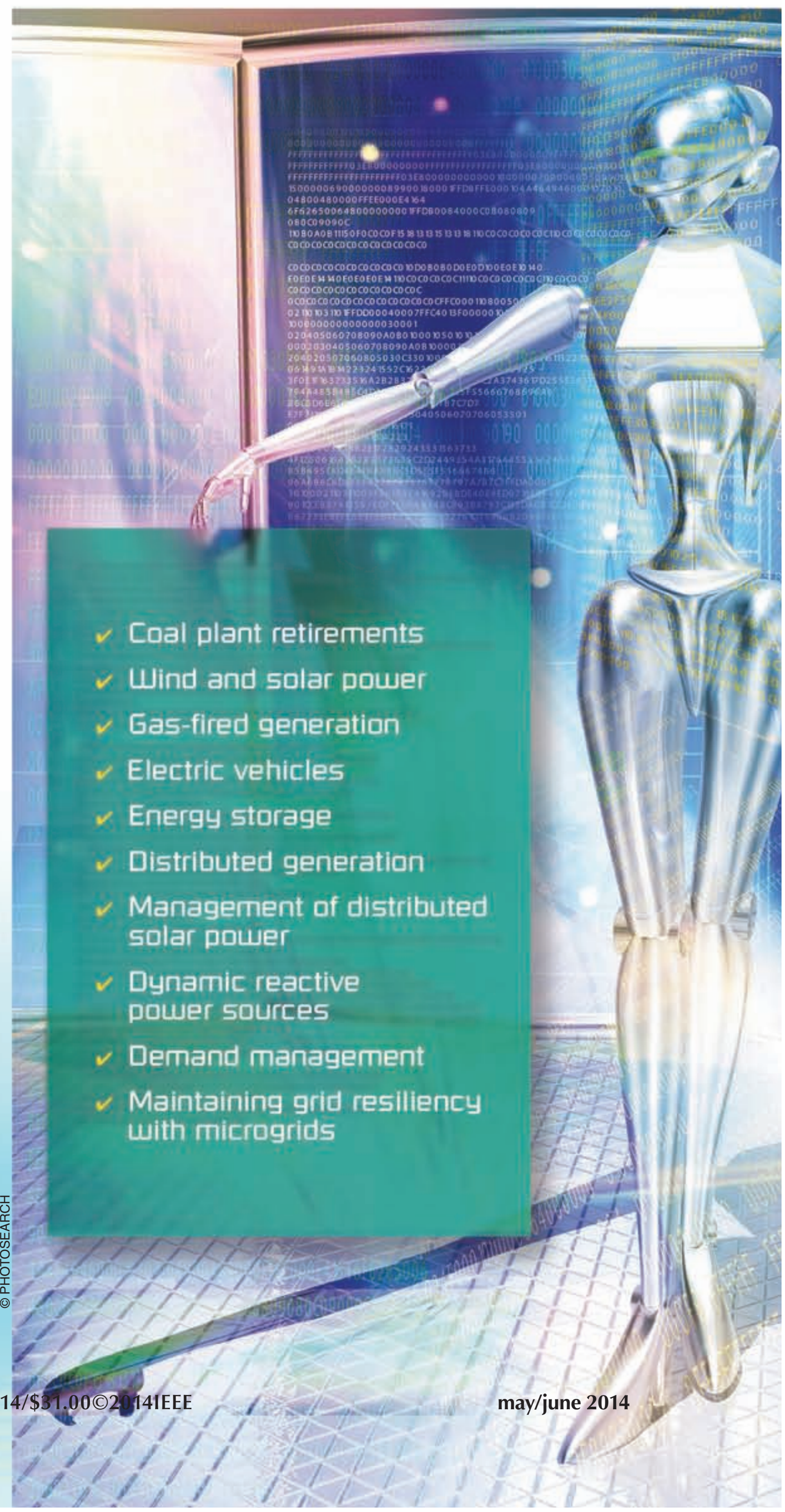
The Grid of the Future

By Devon Manz, Reigh Walling, Nick Miller, Beth LaRose, Rob D'Aquila, and Bahman Daryanian



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FOR OVER A CENTURY, THE MISSION of the power industry has been to build and operate a reliable, affordable, and efficient grid. In the past few decades, developed regions have focused on increasing operational efficiency, while emerging economies have focused on attracting capital to grow their grids. Changing markets, new technologies, and an emerging societal focus on emissions have moved the industry in a new direction. The emergence of modern power electronics, widespread software development, and low-cost communications technologies creates opportunities. The cost-effective extraction of oil and gas in North America is expected to shift our generation mix away from coal and toward natural gas-fired generation. Wind and solar power have proliferated, creating new challenges and opportunities. Advancements in energy storage technologies have revolutionized the consumer electronics industry and paved the way for hybrid and electric vehicles (EVs). In parallel, the resiliency of the aging electric power infrastructure has been questioned in light of the increased frequency and severity of natural disasters, making a

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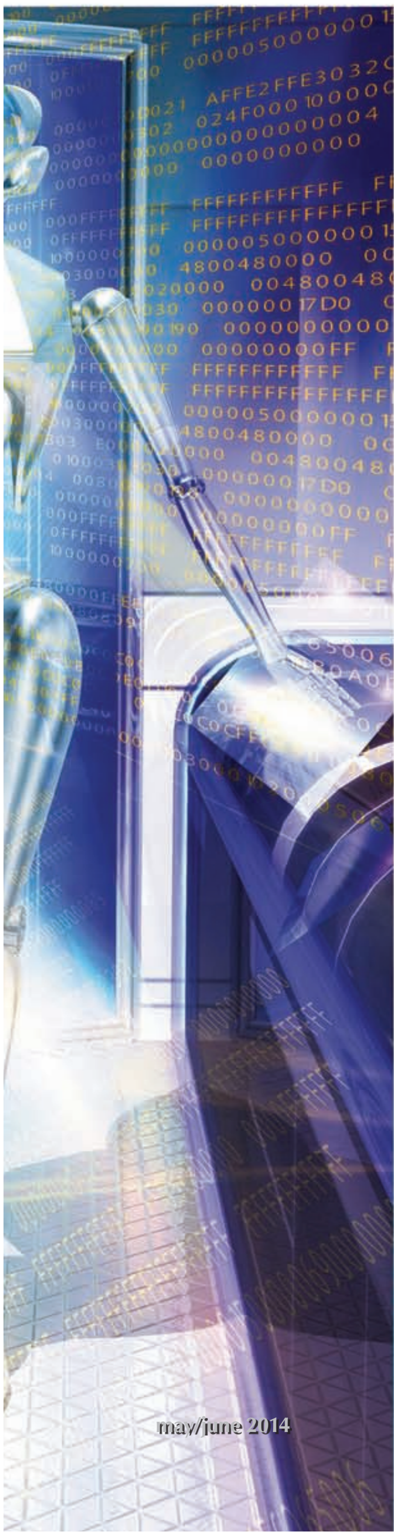
Ten Trends That Will Shape the Grid Over the Next Decade



stronger case for a major investment to build a stronger, more resilient, and sustainable U.S. grid.

Ten Key Trends

Today's electric power industry also manages the interplay of many moving parts and stakeholders. Local, state, and federal policies, the emergence of power marketplaces, and competition drive a fundamental shift away from traditional planning and design disciplines. New evaluation methodologies and analytical tools are being developed to address these emerging needs. This article focuses on presenting the authors' views on ten key trends and their potential impact on shaping the grid of the future.

- ✔ *Coal plant retirements:* Pending regulations and potential greenhouse gas (GHG) policies could lead to a significant retirement of coal-fired generation in the United States. How will the U.S. grid cope with a significant loss of base-load power generation?
- ✔ *Wind and solar power:* Industry's confidence in reliably accommodating nondispatchable resources is increasing while technical advances reduce the cost of wind and solar power. Will we continue to see growth in wind and solar resources?
- ✔ *Gas-fired generation:* Flexible gas-fired generation offers rapid ramping, turn down, and short start times, ideally suited to accommodate more wind and solar generation additions and cope with the retirement of less flexible, aging base-load generation. How will market forces reward the flexibility that will reduce system-wide costs and emissions?
- ✔ *Electric vehicles:* Electric vehicles are increasingly entering the transportation sector. Significant infrastructure investments and policy support will be needed in the near term to accelerate EV adoption. How important is "smart vehicle charging" and economic incentives in this transformation?
- ✔ *Energy storage:* Energy storage faces a cost challenge relative to alternate solutions to the challenges that face the grid. Storage can be an alternative for frequency regulation or short-term reserves. What hurdles must be overcome to see more widespread storage projects? Can storage technologies play a major role in a resilient grid?
- ✔ *Distributed generation:* Distributed generation (DG) growth is being driven by policy [e.g., subsidies and incentives for rooftop solar photovoltaics (PVs)], but DG can provide efficient energy when both electricity and heat are needed in combined heat and power (CHP) applications. Are we going to see DG and microgrids displacing the need for a conventional grid?
- ✔ *Management of distributed solar power:* Rapid growth in distributed solar PVs could challenge the ability of the grid to manage voltage and loading in the distribution system and will create opportunities for new distribution management and voltage control solutions. How will integration challenges impact growth in PVs, and what types of solutions will emerge?
- ✔ *Dynamic reactive power sources:* The retirement of power plants situated near loads, the growth of asynchronous wind and solar power generators, and changing loads on the grid will challenge the grid's reactive power reserves and ability

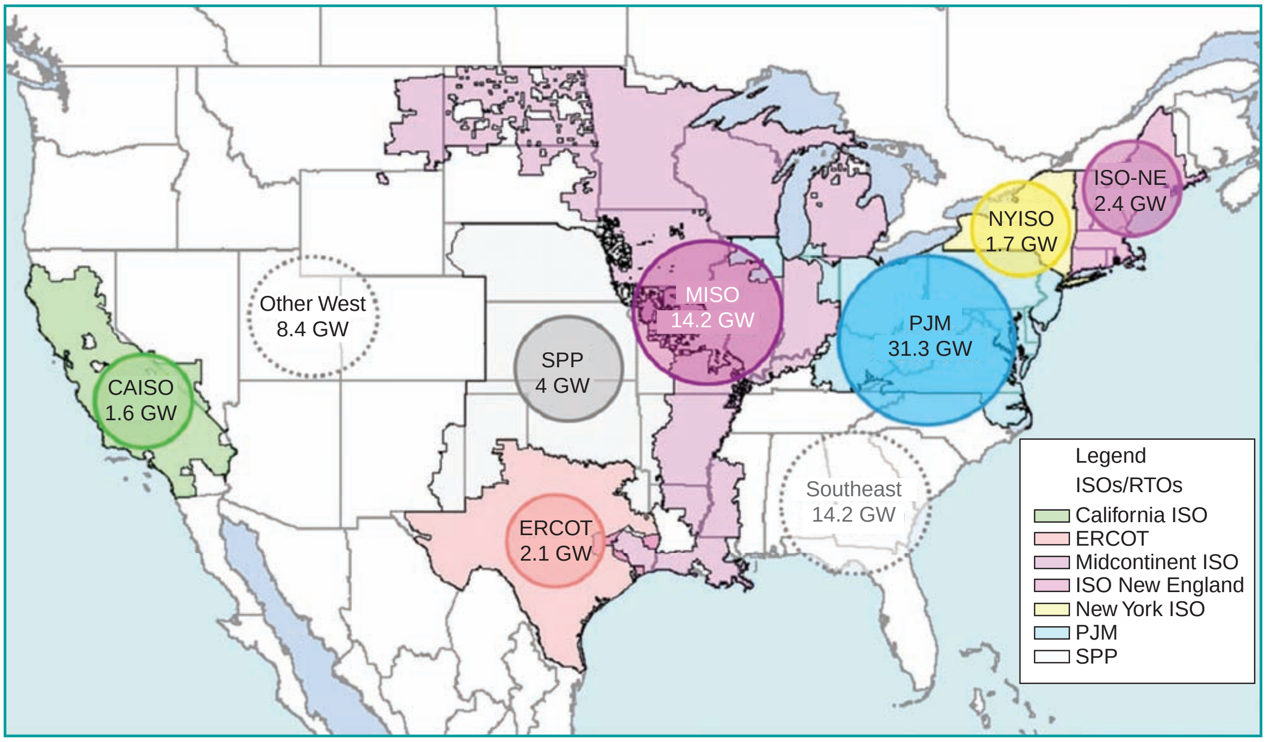


figure 1. Potential coal retirements (map created with Ventyx, an ABB Company, Energy Velocity Suite, Intelligent Map).

to maintain voltage stability. How will the grid maintain steady state and dynamic voltage support?

- ✔ *Demand management:* Generation resources were historically built to provide low-cost electricity and ancillary services and capacity to meet reliability at peak load. Today, demand management can provide these same services. What is the right mix and types of programs and incentives that can maximize the benefits of demand management?
- ✔ *Maintaining grid resiliency with microgrids:* Natural disasters, such as Hurricane Sandy, have registered strongly in the minds of policy makers and have motivated towns, cities, and electric utilities to provide greater operational resiliency for a wide range of critical infrastructure and services. What is the role of small microgrids in providing resiliency to the grid?

While there may be other trends driving the evolution of the grid, the authors expect these ten trends to be at the heart of the discussion in the coming years. The remainder of this article is devoted to more in-depth discussions of each trend.

Coal Plant Retirements

Coal plant owners face an important decision: Should they invest to comply with the proposed environmental regulations or retire their plants? The Environmental Protection Agency (EPA) has proposed a set of rules/standards to reduce air and water pollution: the Cross-State Air Pollution Rule (CSAPR), Clean Water Act Section 316(b), and regulations around hazardous air pollutants such as mercury and air toxics standards, GHGs, and coal combustion residual disposal. In August 2012, CSAPR was vacated by the U.S. Court of Appeals and has reverted back to previous requirements, the Clean Air Interstate Rule, until a valid version of CSAPR can be proposed and implemented. To continue operating, EPA regulations will require coal plant owners to retrofit their plants with environmental control technology or retire the affected coal units altogether.

Based on the authors' estimates, 17 GW of coal capacity was retired from 2010 through September 2013, and about 69 GW more is likely to retire or mothball through 2021 for a total of ~86 GW of coal retirements. The majority of the remaining coal capacity is likely to be retrofitted with technology, such as flue gas desulfurization and baghouses, for a projected cost of approximately US$90 billion expended in 2013 and beyond. Figure 1 shows the projected coal retirement capacity by NERC subregion.

To maintain reliability levels, it is estimated that about 40–50 GW of new capacity will be needed in the United States by 2020 to replace retirements, meet load growth, and maintain reliability. The price of natural gas, the cost of compliance, and the cost of gas-fired generation will affect the rate and amount of coal generation retired. With near-term gas prices around US$4/mmBtu, a high retirement scenario is being born out as reflected in the current estimates of 86-GW total retirements.

The evolution of future EPA regulations is not known, but as it stands, the power industry has opened the door for new generation capacity. Historically, drivers for new generation have hinged on economic growth and the associated load growth that follows. Today, the impact of policy and regulations for environmental sustainability and energy security are also drivers for growth. Historically low natural gas prices and the potential retirement of significant coal-fired generation suggest there could be a resurgence of development in new gas-fired generation over the coming decades.

Wind and Solar Generation

The United States has installed more than 50 GW of wind power, with the vast majority in under a decade. This growth, enabled by cost reductions, improvements in availability and reliability, and strong policy support, continues in the near term. Years in which the coveted wind energy production tax credit was available saw rapid growth in wind power, while years in which the tax credit did not exist saw a significant

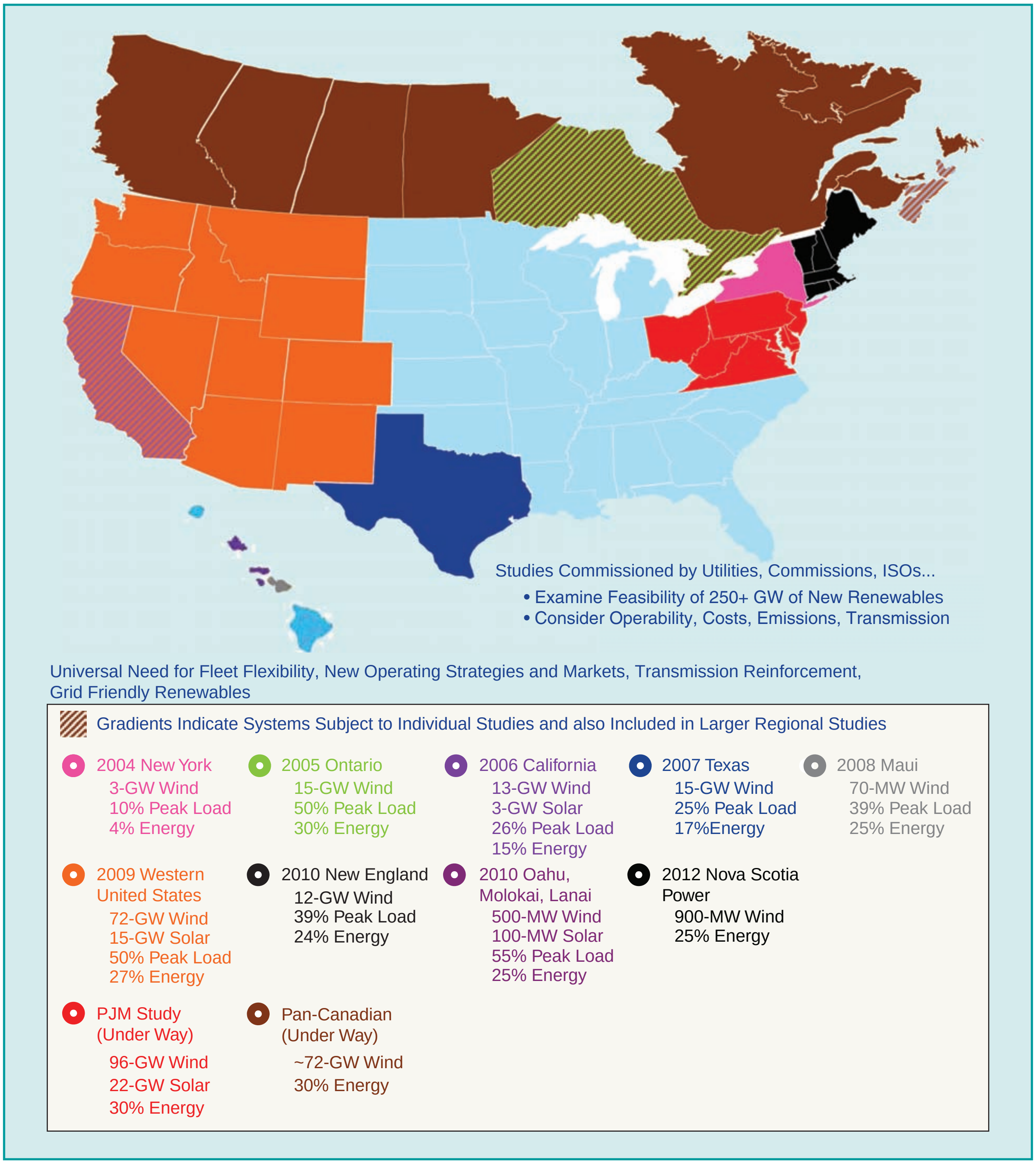
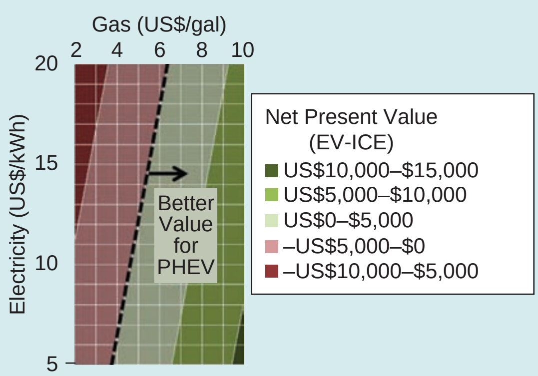


figure 2. Recent GE wind and solar integration studies.

Smart vehicle charging strategies will be critical to avoid potentially dramatic increases in generation, transmission, and distribution capacity requirements.

drop in new wind projects. While many states have renewable portfolio standards, it is not clear if the targets will suffice for continued wind power growth.

Like wind power, the value proposition for solar also relies on policy support in the form of feed-in tariffs in some European countries, an investment tax credit in the United States, and various state-by-state policies ranging from tax credits and renewable energy certificates to net metering policies to renewable portfolio standards. Each of these policies strengthens the value proposition for solar power. It is expected that strong policy support will continue to drive new wind and solar power in the United States. And as solar PV technology rapidly rides down the cost curve, solar power will continue to become more economical. Solar PVs have seen explosive growth in the United States over the past year or two, with PV capacity installations exceeding wind in 2012. In some parts of the United States, solar PVs are on a trajectory to become a significant resource in the generation mix. Wind and solar power continue to grow, even as load growth has slowed. Slow load growth in North America and Europe, and lower natural gas prices in North America, are challenging the economics of wind and solar power. Also, the subsidy to retail PVs provided by net metering policies is under increasing challenge as it inherently involves the transfer of costs to non-PV customers. In the near term, policy support is needed to maintain growth for both wind and solar power.



	PHEV	Hybrid ICE
Vehicle Cost	US$35,000	US$30,000
Fuel Economy	35 kWh/100 mi	51 mi/gal

10,000 mi/Year, 2% Interest Rate (Car Loan)

figure 3. Break-even economics for a hybrid ICE and a PHEV. The maintenance costs for each vehicle were assumed to be equal. (Used with permission from "Integrating Electric Vehicles into the Power System," 2011 CIGRE Symposium).

Gas-Fired Generation

As both wind and solar resources increasingly constitute a significant portion of the generation mix, questions have been raised about the capabilities of the grid to manage the variability and uncertainty of wind and solar power. Numerous wind integration studies have been completed over the past decade, led by groups like the National Renewable Energy Laboratory, various utilities, state commissions, independent system operators, and regional transmission organizations, with each examining the performance and economic impact of integrating high levels of wind power in different regions of the world. A summary of the wind and solar integration studies that GE has led or contributed to is shown in Figure 2. These studies suggest that integrating enough wind power to generate more than 30% renewables by energy is possible, provided the system has adequate generation flexibility, transmission capacity, control area cooperation, and grid requirements for wind plants, to name a few. However, the capacity value of wind power remains relatively low, depending on the geographic diversity of the wind power plants, the size of the control area, and the strength and nature of the wind resources. The uncertainty and variability associated with wind and solar power demands flexibility from the rest of the generating fleet. Flexible generation will be needed as wind and solar plants are built out. Faster starting times, the capability to back plants down further, and higher unit ramping capabiliies are emerging as key needs to support the build out of significant levels of wind and solar power.

As the economics for recovering unconventional natural gas improve, North American natural gas prices are expected to remain relatively low. The relatively low gas prices and the potential retirement of significant levels of coal-fired generation over the next decade will further promote the build out of new natural gas-fired generation. Wind, solar, and gas-fired generation will play a substantial role in the grid of the future.

Electric Vehicles

EVs and plug-in hybrid EVs (PHEVs) are slowly emerging as alternatives to conventional gasoline-fueled vehicles but will

Synchronous condensers are expected to re-emerge as a tried and tested approach to maintaining a stiff grid voltage for stable operation of the grid of the future.

continue to need strong incentives and a relatively high cost of gasoline to be viable. A key driver for these vehicles in the United States is the desire to reduce U.S. dependence on oil and reduce tailpipe emissions. Today there is strong policy support with a U.S. tax credit of up to US$7,500 for new EVs and PHEVs, which substantially covers the cost of the battery system, estimated today to cost as much as US$10,000 per vehicle, depending on the vehicles' range.

At today's gasoline and electricity prices, it will be some time before EVs are truly a cost-competitive alternative to conventional gas-fueled vehicles without policy support. If the cost of batteries is substantially reduced and a new car buyer, who drives 10,000 mi per year, is faced with a decision to buy a US$35,000 PHEV or a US$30,000 gas-fueled vehicle, the driver should still opt for a gas-fueled vehicle if economics are the determining criterion for the buyer. Today, a Toyota Prius achieves 51 mi/gal. A PHEV driving in all-electric mode is the favored alternative to a Prius only when gasoline prices exceed US$6/gal, assuming that the PHEV is charged with US$.18 per kWh electricity. Even if the price of electricity were US$.07 per kWh, the price of gasoline would still need to exceed US$4/gallon for the economic value of the PHEV to exceed that of the Prius. This is shown in Figure 3. At today's fuel prices, lower battery costs and stronger incentives are needed for these vehicles to make substantial inroads into the transportation sector. Even if the cost of the battery falls by 50%, incentives will still be needed to enable widespread growth of EVs and PHEVs. It took more than ten years for hybrid vehicles to constitute 2.5% of the U.S. vehicle market. It may take many years for EVs to reach a significant portion of the vehicle fleet.

If EVs are able to gain a substantial share of the automotive market, they will drive substantial load growth. A recent GE study showed that, for one region, transitioning 10% of the light-duty vehicle fleet to EVs would increase the load energy by ~5%. The implementation of a charging infrastructure for EVs and PHEVs offers a substantial new business opportunity. For the system studied, "smart" vehicle charging costs 19% less than serving uniform load growth, while completely uncontrolled charging costs 24% more (see Figure 4). These savings could be used to invest in the technologies needed to enable smart charging, provide customer incentives that promote controlled charging, and provide savings to customers. For the system examined, the difference in energy production cost between uncontrolled and smart charging equated to ~US$300/year per PHEV owner. In addition to the energy production cost savings, there are savings due to avoided power generation and delivery infrastructure otherwise needed to support increased peak demand driven by uncontrolled charging.

Uncontrolled EV charging can result in a substantial increase of peak load and a deterioration of system load factor. The peak-load increase could drive a substantial, and uneconomical, increase in generation, transmission, and distribution capacity to support this peak. Of these, the generation capacity costs to meet increased peak are typically dominant. If EV charging is appropriately controlled, the required energy can be supplied without an increase in peak system demand, and thus the high costs of incremental generation capacity to support EV charging can be avoided or deferred. Controlled EV charging could prove to be a significant beneficial asset for managing light load system operational challenges. However, even with the control of system peak demand, there may be the impact of EV charging on

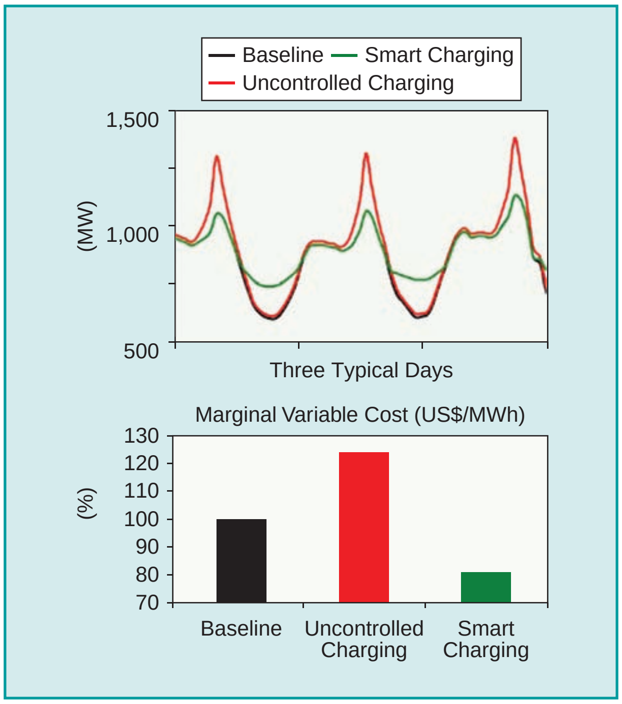


figure 4. Marginal variable cost of serving the EV load for two EV charging strategies, with respect to the marginal cost of serving uniform load growth. (Used with permission from "Integrating Electric Vehicles into the Power System," 2011 CIGRE Symposium.)

figure 5. GE/GNB and Metlatkla Power and Light battery energy storage system in Alaska. (Reprinted with permission from George Hunt, GNB/Exide.)

transmission and distribution assets due to localized EV concentration or loading factors not directly related to just peak demand, such as limiting transformer cool-down during off-peak periods. Replacing overloaded transformers, reconfiguring heavily loaded distribution circuits, and building new substations may be needed in areas that experience sudden increases in EV charging loads. These system modifications and equipment additions/upgrades are expected to be manageable and reasonably small relative to the cost of the EVs and the charging infrastructure if charging patterns are managed. Smart vehicle charging strategies will be critical to avoid potentially dramatic increases in generation, transmission, and distribution capacity requirements.

Energy Storage

The grid is the ultimate "just-in-time" system, instantaneously serving customer load with generation that is precisely dispatched and controlled to match the load. Energy storage presents the capability to relax this constraint. Historically, the power system has been designed and controlled to manage variability in load by increasing or decreasing the output of generation. Wind and solar power exacerbate the variable power needed from the rest of the generation. However, sudies by the authors suggest that the variability of wind and solar power, when more than 30% of the annual energy is generated by these resources, can be managed by the grid. Generally, the significant wind and solar variability smoothing effect observed over large areas (similar to that of the load smoothing effect of a neighborhood relative to that of a single home) does not necessitate the *need* for energy storage. However, the grid is demanding more flexibility. This is manifesting in a greater need for frequency regulation and reserves. Wind turbine manufacturers have responded to this trend and advanced wind turbine technology to better manage variations in wind power output. For example, GE is currently offering a hybrid wind turbine with integrated battery energy storage that can competitively self-supply incremental ancillary services, given suitable power market structures.

While storage has not yet found widespread use in the grid, a long list of potential applications for storage has been cited. Applications that require substantial energy ratings range from capturing lower cost energy to displace higher cost energy at a later time, price arbitrage, or shifting energy from one time to another to avoid overloading equipment. In general, these applications do not currently offer strong value propositions as the cost of energy-storage technologies is high relative to energy prices and conventional approaches for managing overloaded equipment. It is the applications that demand the sudden injection or removal of energy of short durations that seem to offer the greatest value. Niche applications already exist, and more are emerging. Isolated systems with very high electricity costs also tend to have relatively high regulation and reserve requirements. Meeting some of these ancillary service requirements with energy storage rather than high-cost fossil fuel generation has the potential to be highly economical. For utilities operating in regions of the United States where there are no organized power markets, the evaluation of energy storage versus other sources of operational flexibility needs to be done on a cost-avoidance basis, rather than from ancillary service market revenues. For example, in the 1990s, GE worked with GNB/Exide Technologies to build a battery storage system in Metlakatla, Alaska, to reduce the use of expensive diesel-fired generation. The system is shown in Figure 5. The roughly US$2 million battery system reduced the diesel fuel bill by more than US$6 million over its 12 years of operation.

Even in large grids, storage can be an alternative provider of regulation. The application of storage in this case is not driven by necessity but must be economically competitive with generation flexibility. Power market prices for frequency regulation vary daily and seasonally. During periods of scarcity, prices can be high. The cost of storage for frequency regulation is approaching the average current prices for regulation in some energy markets. It remains to be seen if energy storage, without subsidies, can be truly competitive in the regulation application.

More applications are also being observed. Urban centers experiencing line or transformer overloads, with no room available for new equipment, may benefit from storage located closer to the loads to avoid expanding the substation or reconfiguring the lines. In September 2013, the California Public Utilities Commission issued a proposed Decision Adopting Energy Storage Procurement Framework and Design Program to address the policies and mechanisms for the procurement of electric energy storage pursuant to California Assembly Bill (AB) 2514. One of the objectives is to employ storage technology to help maximize existing generation and transmission investment and operation, integrate renewables, and minimize GHG emissions. The framework sets forth the storage targets for the investor-owned utilities and the procurement requirements for other load-serving entities in California, the procurement mechanisms, and the program evaluation criteria.

Ultimately, storage is another resource that can provide the grid with flexibility. As the grid evolves, flexibility requirements are likely to increase, and traditional sources of flexibility may be displaced. As the cost of storage decreases and more applications emerge, storage will contend with strong competitors in the form of demand response (DR), flexible fossil fuel-based generation, and other emerging technologies. While there are no challenges in the operation or performance of the grid for which storage is the only solution, applications where storage is the best technical and most cost-effective alternative do exist.

Distributed Generation

Electric power infrastructure originated over a century ago when isolated small generators supplied nearby loads. As the infrastructure rapidly evolved, the benefits of a system based on centralized generation emerged. Central generation within interconnected systems produced benefits of scale, diversification of loads, improved energy resource flexibility, and increased reliability. These outweighed the costs of the transmission and distribution infrastructure needed to connect the central generation with distributed loads and set a trend that evolved toward a large interconnected grid. More recently, regulatory changes, technical advancements, and environmental impacts have led to a significant increase in DG applications.

The definition of DG is somewhat ambiguous. There is presently no uniformly accepted industry definition, and definitions can vary from nondispatchable solar PVs located on the customer side of the meter to cogeneration facilities at large industrial sites with ratings of 100 MW or more. The drivers behind most customer-owned DG applications can be tied to one or more of the following:

- ✔ Utilize a locally available energy source that cannot be easily transported, such as biogas or sun.
- ✔ Increase efficiency by generating electricity and using exhaust for heating (CHP).
- ✔ Provide lower-cost electricity than that of the local utility. This may involve peak shaving for commercial facilities billed for demand charges.
- ✔ Take advantage of policy-driven economic incentives such as feed-in tariffs, net-metering rules, and rebates specific to DG.
- ✔ Increased reliability to a facility where the DG is located.
- ✔ Fulfill social and sustainability goals, including the desire to be independent from the utility, create microgrids for resiliency and security, and other similar values that cannot be measured purely in a pro-forma analysis.

Independent power producers and utilities may choose to connect at the distribution level when the scale of their development is small or when policy provides specific incentives for distribution interconnection. In general, generation built close to load, in locations that alleviate transmission congestion, will generate greater revenue in the wholesale market. Some utilities have also implemented strategies where DG is used to alleviate localized overloads of existing distribution substation capacity, where the cost of the next substation capacity step is excessive relative to the size of the overload.

The value of DG in offsetting transmission and distribution capacity requirements, however, is much less, and more indirect, than commonly perceived. To provide an effective substitute for transmission and distribution assets, DG output must be available at the time of system peak. This usually requires that the DG be dispatchable and contractually obligated to provide support when needed. Also, because individual generation equipment has a lower reliability and availability than the utility service we receive at our homes, DG redundancy needs to be considered. Where only a few DG units are involved, the costs to provide reliable capacity could be sizeable.

While wind generation and hydro power are presently the largest renewable energy sources in the grid, solar PVs represent the most rapidly growing DG segment. In general, the unsubsidized cost of PV is high relative to alternate forms of generation. When PVs are connected "behind the meter" on the roofs of customers, the electricity produced will displace the electricity typically provided by the utility. Where net metering tariffs are in place, the effective value to the owner of the generated energy is equal to the retail energy rate. Today, many utilities recover their fixed service costs through retail rates based entirely on the energy provided to the customer. Since the grid service will still be needed on the cloudy days when PVs are unable to entirely displace the utility electricity supply, much of the fixed service costs remain unchanged. Thus, utilities may need to consider alternative tariff structures to adequately recover these fixed costs without placing undue burden on the customers who are not self-generating. These alternatives could include demand charges, similar to those experienced by industrial customers, or larger fixed service charges. Either will tend to decrease the energy-based electricity rates. While PVs are approaching grid parity relative to conventional volumetric (kWh-based) retail electricity rates in some regions of the country, pricing mechanisms may change to ensure that the true cost of electric service is properly reflected in its price.

The aforementioned drivers for DG will continue to increase their presence in the grid of the future. The dominant driver for DG in North America will be policy, particularly those that promote renewable generation and grid resiliency. Distributed solar PVs and CHP will likely be the most pervasive form of DG. While growth in DG will continue, there is a long-term cost savings driver toward a grid comprised of centralized generation.

Managing Distributed Solar PV

Solar PVs have historically been applied as a small-scale distributed resource. However, in recent years, there has been explosive growth in large utility-scale PV power plants, with some facilities currently planned to exceed several hundred megawatts of capacity. Unlike wind, solar PVs do not suffer a large cost penalty when scaled to a small size. Thus, PV installations in the future are expected to be well divided

> Solutions for intelligent distribution controls that provide necessary coordination between many devices, including distributed PV, are evolving.

between small distributed applications and large utility-scale plants.

The integration of large-scale PV plants in the transmission system can follow the successful model already established by wind integration, with the consequential impact of variability treated in the same manner. At the distribution level, locally high penetrations of connected PV capacity can be very disruptive to operations. Power variability due to intermittent cloud shading of PVs, in itself, is not of concern at the distribution level because energy balance is achieved on a much wider basis at the transmission level. However, the consequential impact of power variability is voltage variation that can cause premature failure of utility voltage-regulating equipment and power quality degradation for all customers served by the distribution system.

While energy storage is often discussed as a mitigating approach, voltage variations can, in most cases, be much more economically addressed using reactive power. Dynamic reactive devices, such as static synchronous compensators (STATCOM) and static var compensators (SVCs) can be applied to mitigate voltage variations at the feeder level and cover the temporal range of PV variability that cannot be mitigated by mechanically switched voltage regulators. IEEE Standard 1547 has until recently prevented PVs from participating in providing mitigation of these problems. Recent modifications to the standard have opened the door for advanced inverters to use their reactive power capability to help mitigate voltage variations caused by PVs. Solutions for intelligent distribution controls that provide necessary coordination between many devices, including distributed PVs, are evolving and are expected to help manage this emerging challenge that faces the grid.

Dynamic Reactive Power Sources

The growth in wind and solar power and DG and the retirement of coal plants and other large aging central-station generation plants will have an unintended consequence on the performance of the transmission system. Today, many of the oldest thermal units are located near large urban load centers. These units, which may be retired or displaced in the near future, often provide essential voltage support and needed short-circuit strength. This dynamic support is critical to maintain a strong and stiff voltage for the stability of the grid during and after disturbances such as the loss of a major transmission line. Unlike active power (watts), the need for and the provision of reactive power (vars) is highly locational. Since utility-scale wind and solar plants tend to be built far from load centers, the reactive power produced on a remote windy plain or out in the sunny desert is of little value to maintaining voltage in urban load centers.

Historically, nearly all electricity transmitted through the grid was delivered via synchronous generators equipped with excitation systems. In contrast, wind and solar use asynchronous generating technologies that contribute little to short-circuit strength. Wind and solar energy can provide the necessary dynamic reactive power to the grid to support voltage for normal operating conditions, but these asynchronous generators do not create the same level of voltage stiffness during deep grid disturbances as conventional synchronous generators. In addition to loss of dynamic reactive capability near load centers, there is growing evidence that the aggregate load on the grid is becoming less "grid friendly." Modern electronic loads, air conditioning, and computers can all increase the requirement for dynamic reactive support. The retirement of conventional generators and the displacement of remaining generators with wind and solar power could alter the present systems' capabilities to manage disturbances on the grid.

Generation retirements are typically announced fewer than two years before the planned retirement date, making the lead time for needed grid reinforcements short and transmission solutions impractical. For many voltage problems, shunt capacitors are a relatively inexpensive approach and can be installed quickly. However, shunt capacitors cannot regulate voltage dynamically due to the discrete switching necessary for operation. Power electronics, such as SVCs, have been used successfully for many years to meet dynamic voltage regulation requirements but require a stiff grid voltage that is created by nearby generation. More advanced power electronic devices such as STATCOM can provide improved performance in a weaker grid, but in a very weak grid they still have limited ability to stabilize voltage during a disturbance. The most robust and often the only viable option is synchronous condensers, which replicate the dynamic reactive power capability of a conventional power plant without the capability of generating power for the grid. An emerging trend in North America is the conversion of retired generation to synchronous condensers. This involves removing the turbine and operating the synchronous generator to produce only reactive power. This is often a very attractive approach from both a system performance and economic perspective.

Wind, solar, and gas-fired generation will play a substantial role in the grid of the future.

As loads become less grid friendly, as more wind, solar, and other asynchronous forms of power generation displace conventional power plants, and as older plants are retired, the grid will need both local dynamic reactive power sources and the means to maintain adequate short-circuit strength. Synchronous condensers are expected to re-emerge as a tried and tested approach to maintaining a stiff grid voltage for stable operation of the grid of the future.

Demand Management

Demand management or DR covers the whole range of demand-side resources from direct load control (operators disconnect load on demand) to responsive demand based on dynamic pricing and other control signals (price schedules or signals are passed to customers to incent load reduction). The advent of new technology is enabling more sophisticated and engaging DR options that, coupled with dynamic pricing, are making possible more flexible and robust customer response behavior. Smart grid innovations in advanced metering infrastructures, communications, home emergency management systems, and smart appliances are making DR both technologically feasible and economically viable, enabling a wider deployment.

Despite the relatively slow economy, utility and retail DR programs are being driven by state regulatory commissions and by utilities in need of managing their peak demand and reducing long-term capacity costs. Furthermore, FERC orders #719 and #745 are opening up opportunities for the participation of DRs in wholesale markets, with DR to be paid ISO locational marginal prices and to be treated similarly to supply-side resources in energy, capacity, and ancillary services markets. DR benefits utilities, customers, and the power system in a number of ways, including deferring the need for new investment in generation and transmission, increased reliability, and increased economic efficiency by price responsive (and price-elastic) demand.

FERC estimates that, if the current level of DR is preserved through the next decade, DR would shave 38 GW off U.S. peak demand in the year 2019, and, with dynamic pricing, the total potential could range between 14 and 20% of peak demand or 138–188 GW depending on whether dynamic pricing is deployed on an opt-in or opt-out basis. The Brattle Group estimates US$65 billion in cost avoidance in the United States through 2030 from DR. With the proper alignment of technology, pricing, and incentives, DR is expected to play a key role in the value proposition for the grid of the future.

Grid Resiliency

Recent disasters in the United States, such as the 9/11 terrorist attack in 2001 and Hurricane Sandy in 2012, have highlighted a vital need for preventing power disruptions and blackouts that paralyze the operations of essential services and disrupt the provision of key necessities to the population at large. These include such services as those provided by the first responders, police departments, fire houses, hospitals, emergency shelters, elderly care facilities, water utilities, sewage treatment facilities, public transit systems, and other essential government and business operations.

According to the U.S. Department of Energy, outages caused by severe weather such as thunderstorms, hurricanes, and blizzards account for 58% of outages observed since 2002 and 87% of outages affecting 50,000 or more customers.

In June 2011, President Obama released "A Policy Framework for the 21st Century Grid," which set out a four-pillared strategy for modernizing the electric grid. The initiative directed billions of dollars toward investments in 21st century smart grid technologies focused on increasing the grid's efficiency, reliability, and resilience, thereby making it less vulnerable to weather-related outages and reducing the time it takes to restore power after an outage. Recently, in August 2013, the Executive Office of the President issued the report "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages," which estimates the annual cost of power outages caused by severe weather between 2003 and 2012 and describes various strategies for modernizing the grid and increasing grid resilience.

One such strategy to make certain critical areas of the system more robust is by employing microgrids. Microgrids can be a useful means of providing electric service resiliency to certain areas by enabling sustainable operations and uninterrupted functioning of critical load in islanded mode in the event of widespread disruptions in electric utility services. The U.S. Department of Energy defines the term "microgrid" to mean "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode." Well-designed microgrid systems, which may include a combination of DG, energy storage, and DR, with an intelligent system platform that enables system integration, communication, monitoring, and smart control, would function seamlessly in a sustainable manner during contingency periods and judiciously utilize available resources on a selective manner to ensure continued operation of the critical loads.

Microgrids are particularly applicable when a facility or condensed load area has relatively secure intrafacility interconnections (e.g., underground distribution) but is supplied by relatively vulnerable connections to the grid. In the more general situation of entirely overhead supply and local distribution lines, the distribution secondaries and laterals tend to be more vulnerable to storm damage than the trunk feeders and subtransmission lines. With the likely unavailability of local interconnections following a storm or disaster, the microgrid model is less applicable in this more general situation.

Microgrids are just one potential approach to improving resiliency. A comprehensive strategy considers all the measures available, including intelligent approaches such as automated distribution reconfiguration, as well as lower-technology approaches such as moving distribution underground and increasing tree trimming.

Moving forward, a necessary step is the development of national and regional policies that place value on a resilient energy supply. These policies should focus on the definition and achievement of desired outcomes, such as the preservation of power supply to critical loads. Policies should be technology neutral, allowing existing and new strategies, including microgrids, to meet their objectives. In any event, all future systems designed for resiliency may have to be custom designed and implemented on a case-by-case basis to be suitable for their intended settings (e.g., urban, suburban, and rural) and appropriate for a different mix of government, civic, and business entities within each setting. The grid of the future will employ a spectrum of existing and new technologies to ensure grid resiliency during and following disasters.

Conclusions

New technologies, changing market conditions, more frequent extreme weather events, and new regulations and policies all shape the future of the grid. This is true for both the emerging and developed economies of the world. The many moving parts of policy, regulations, and market conditions and the cost and performance of new and existing technology makes it difficult to place bets as a product vendor, utility planner, or investor. While many factors will shape the future of the grid and many others can alter its course, the ten trends described in this article are some of the key drivers that will shape the grid over the next decade.

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Selling Into the Sun:

Price Premium Analysis of a Multi-State Dataset of Solar Homes

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SELLING INTO THE SUN: PRICE PREMIUM ANALYSIS OF A MULTI-STATE DATASET OF SOLAR HOMES

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Abstract

Capturing the value that solar photovoltaic (PV) systems may add to home sales transactions is increasingly important. Our study enhances the PV-home-valuation literature by more than doubling the number of PV home sales analyzed (22,822 homes in total, 3,951 of which are PV) and examining transactions in eight states that span the years 2002–2013. We find that home buyers are consistently willing to pay PV home premiums across various states, housing and PV markets, and home types; average premiums across the full sample equate to approximately $4/W or $15,000 for an average-sized 3.6-kW PV system. Only a small and non-statistically significant difference exists between PV premiums for new and existing homes, though some evidence exists of new home PV system discounting. A PV green cachet might exist, i.e., home buyers might pay a certain amount for any size of PV system and some increment more depending on system size. The market appears to depreciate the value of PV systems in their first 10 years at a rate exceeding the rate of PV efficiency losses and the rate of straight-line depreciation over the asset's useful life. Net cost estimates—which account for government and utility PV incentives—may be the best proxy for market premiums, but income-based estimates may perform equally well if they accurately account for the complicated retail rate structures that exist in some states. Although this study focuses only on host-owned PV systems, future analysis should focus on homes with third-party-owned PV systems.

Key words: photovoltaic, PV, solar, homes, residential, property value, selling price, premium, hedonic, California, new homes, existing homes, host-owned

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1. Introduction

As of the second quarter (Q2) of 2014, solar photovoltaic (PV) energy systems have been installed on more than a half million homes in the United States; more than 42,000 systems were installed in Q2 alone, roughly four times the number installed in the same quarter in 2010 (SEIA & GTM, 2014). This growth is in part related to the dramatic decrease in installed PV costs over the last 10 years (Barbose et al., 2014) as well as the increase in financing options for property owners installing PV, such as leased PV systems and other zero-money-down purchase options (SEIA & GTM, 2014).

As PV installations have proliferated, so has the number of transactions involving homes with PV (Hoen et al., 2013b). Because of this, the real estate sales and valuation communities have been working to enable a better understanding of the valuation of PV systems and green features more generally (Adomatis, 2014). For example, courses on the marketing and valuation of green features are available through the Appraisal Institute and the NATIONAL ASSOCIATION OF REALTORS® (NAR)[1]; green attributes for a multiple listing services data dictionary have been recommended by a working group of the NAR (2014); the Appraisal Institute has developed a "Residential Green & Energy Efficient Addendum" to capture green attributes during an appraisal[2]; PV Value®, a web-based tool specifically designed for the valuation of PV systems, has been developed (Klise et al., 2013); the National Home Performance Council and CNT Energy developed a blueprint to make energy improvements more visible in the real estate market (CNT Energy & NHPC, 2014); Fannie Mae, in its updated standards for conforming loans it will repurchase, now mentions homes with solar panels and the need to "adjust" the appraised value of the home if the market warrants it (Fannie Mae, 2014); and, finally, the Federal Housing Administration has proposed requirements for valuing "Special Energy Related Building Components" in its *Draft Single Family Housing Handbook*, which governs conforming loans for homes with PV systems (FHA, 2014).

Despite the activity around valuing (and marketing) PV homes, little research documents the premiums for these homes. Farhar and Coburn (2008) first documented the apparent increase in values for 15 PV homes inside a San Diego subdivision. This was later corroborated by strong empirical evidence from greater San Diego and Sacramento (Dastrup et al., 2012) and from a relatively large dataset of approximately 1,900 California PV homes (Hoen et al., 2011; 2013a; 2013b); these studies employed hedonic pricing models to estimate premiums. Finally, a case study of 30 PV homes that sold in the Denver metro area found evidence of premiums (Desmarais, 2013). Because the evidence that PV homes garner a premium has focused on a relatively small number of California homes and a few in Colorado, there is need for further evidence of premiums outside of California and even inside California. There is also a need to analyze transactions that occurred after the recent housing bubble, the period from which most previous data had been collected and analyzed (Hoen et al., 2011; 2013a; 2013b).

In most local markets, few PV home sales occur, thus appraisers and other real estate professionals (real estate agents, lenders, underwriters, etc.) often cannot compare similar PV and non-PV home sales to derive a PV premium. Because of this, valuation professionals often use other methods to value PV systems, including the income and cost methods (Adomatis, 2014; FHA, 2014). Hoen et al. (2013b) used hedonic (regression) modeling, employing similar methods as the sales-comparison approach, and found premiums larger than the contributory values generated with the cost and income approaches—a counterintuitive result. Possible reasons for this result include issues with the underlying dataset, which

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[1] See, e.g., http://www.appraisalinstitute.org/education/education-resources/green-building-resources/ and http://www.greenresourcecouncil.org/.

[2] See http://www.appraisalinstitute.org/professional-practice/professional-practice-documents/new-residential-green-energy-efficient-addendum/.

included sales from homes with a very wide range of prices and sales that occurred largely during the housing boom. In addition to that California-based study, Desmarais (2013) compared the three methods in her analysis of 30 Colorado sales but did not use statistical tests. Therefore, additional comparison of the various methods—using a more recent dataset, statistical methods, and a broader group of transactions—would be a valuable contribution to the literature.

Other considerations are important as well. The gross installed costs (i.e., costs before state and federal incentives) of PV systems have declined steadily in recent years, while net costs (i.e., with incentives included) have remained fairly stable (Barbose et al., 2014). Examining premium changes over this period might indicate how the market responds to signals from gross and net costs. Moreover, over the same period, the housing market saw significant swings: the housing bubble, the subsequent crash, and then the recovery. Understanding whether observed PV premiums varied over this period would help illuminate how enduring these premiums might be. There also has been evidence that the new home market in California heavily discounted PV homes during the housing boom and bust (through 2009) in comparison to the premiums garnered by existing home sellers (Hoen et al., 2011; 2013a).[3] Therefore, examining how new home PV premiums fared in relation to existing home premiums within an expanded dataset would be of interest.

In addition, others have explored the existence of a green cachet, such as the "Prius effect" and other forms of "conspicuous (non)consumption," where buyers appear to pay more for a "green" item than they will save over its life in decreased energy costs (White, 1978; Kahn, 2007; Sexton, 2011). Dastrup et al. (2012) find larger PV premiums where more Prius hybrid vehicles are registered, which they use as a proxy for environmental leanings. This analysis concentrated on only the San Diego and Sacramento areas, thus analysis of a broader dataset is warranted.

Finally, previous literature suggests the need for more research on the market's depreciation of aging PV systems, especially for systems greater than 6 years old, which have not been well studied because of the immaturity of the PV market (Hoen et al., 2011; 2013a; 2013b). A clearer understanding of how the market depreciates PV systems would likely enhance appraisal techniques.

In summary, there are a number of gaps in the literature, each of which the present research seeks to address:

1. Are PV home premiums evident for a broader group of PV homes than has been studied previously both inside and outside of California and through 2013?
2. Are PV home premiums outside of California similar to those within California?
3. How do PV home premiums compare to contributory values estimated using cost and income methods?
4. How did the size of the premium change over the study period, as gross PV system prices decreased and during housing market swings?
5. Are premiums for new PV homes similar to existing PV home premiums?
6. Is there evidence of a "green cachet" for PV homes above the amount paid for each additional watt added?
7. How does the age of the PV system influence the size of the PV premium?

[3] These discounts, it was assumed, were offset by decreased marketing times (i.e., "sales velocity") for these homes, a priority for home builders as the market for new homes slowed and inventories increased (Dakin et al., 2008; Farhar and Coburn, 2008; SunPower, 2008).

It is important to clarify that this research focuses on only host-owned PV systems and therefore excludes third-party-owned systems, which, we recommend, should be the focus of future research.

The remainder of this report is organized as follows: Section 2 discusses our methodological approach; Section 3 details the data used for the analysis; and Section 4 presents the results, followed by a discussion of the results in Section 5 and conclusions in Section 6. An appendix detailing cost estimate preparation follows the references.

2. Methodological Approach

To examine the questions above, this research relies on a hedonic pricing model—the "Base Model"—against which a series of other models are compared. Those other models use a subset of the data (e.g., new or existing homes), an interaction term(s) (e.g., age of the PV system), or other variants to examine the various research questions and test the overall robustness of the results.

The basic theory behind the hedonic pricing model starts with the concept that a house can be thought of as a bundle of characteristics. When a price is agreed upon between a buyer and seller, there is an implicit understanding that those characteristics have value. When data from a number of sales are available, the average marginal contribution to the sales price of each characteristic can be estimated with a hedonic regression model (Rosen, 1974; Freeman, 1979; Sirmans et al., 2005). This relationship takes the basic form:

Sales price = f (home and site, neighborhood, and market characteristics)

"Home and site characteristics" might include, but are not limited to, the number of square feet of living area and the presence of a PV system. "Neighborhood" characteristics might include such variables as the crime rate and the distance to a central business district. Finally, "market characteristics" might include, but are not limited to, temporal effects such as housing market inflation/deflation.

2.1 Base Model

The "Base Model" to which other models are compared uses a relatively simple set of home and site characteristics: size of the home (i.e., square feet of living area); age of the home at the time of sale (in years); age of the home squared (in years); size of the parcel (in acres) up to 1 acre; and any additional acres more than 1 (in acres).[4] It also includes the presence and size of the PV systems. To control for neighborhood, we include a census block group fixed effect, which, in all cases, includes at least one PV home and one non-PV home.[5] Finally, market characteristics are accounted for by including a dummy variable for the quarter and year (e.g., 2013 Q2, 2009 Q1, etc.) in which the sale occurred. This model form was chosen for its relative parsimony, its high adjusted R^2, and its transparency.[6] It is estimated as follows:

$$\ln(\mathrm{P}_{\mathrm{itk}}) = \alpha + \beta_1\left(\mathrm{T}_{\mathrm{i}}\right) + \beta_2\left(\mathrm{K}_{\mathrm{i}}\right) + \sum_{\mathrm{a}} \beta_3\left(\mathrm{X}_{\mathrm{i}}\right) + \beta_4\left(\mathrm{PV}_{\mathrm{i}} \cdot \mathrm{SIZE}_{\mathrm{i}}\right) + \varepsilon_{\mathrm{itk}} \tag{1}$$

[4] Acres is entered into the model as a spline function using two variables, up to 1 acre (*acreslt1*) and any additional acres above 1 (*acresgt1*), to capture the different values of up to the first and additional acres of parcels in the sample. Therefore *acreslt1 = acres* if *acres* ≤ 1 and 1 otherwise, while *acresgt1 = acres*-1 if *acres* > 1 and 0 otherwise. Additionally, square feet and age squared are entered into the model in 1,000s to allow for easier interpretation of the coefficients.

[5] A census block group contains approximately 600 to 3,000 people. By including this fixed effect, and requiring each to contain at least one PV and one non-PV home, the PV estimates are, therefore, essentially a comparison of those two home types within the block group, while controlling for temporal and characteristic differences between them.

[6] Model choice for this work was based on extensive robustness model exploration in previous analysis (Hoen et al., 2011; 2013a; 2013b). Other models were explored but are not presented here. They include adding other home and site parameters such as number of bathrooms, condition of the home, and if a pool is present, all of which further limited the dataset but did not substantively affect the results. Similarly, instead of using a fixed effect for sale year and quarter, interacting sale year and, separately, sale quarter, with a geographic variable, such as county, to control for geographic variation in market inflation/deflation was explored with no change to the results.

where

P_{itk} represents the sale price for transaction *i*, in quarter *t*, in block group *k*,

α is the constant or intercept across the full sample,

T_i is the quarter *t* in which transaction *i* occurred,

K_i is the census block group *k* in which transaction *i* occurred,

X_i is a vector of *a* home and site characteristics for transaction *i*,

PV_i is a fixed-effect variable indicating a PV system is installed on the home in transaction *i*,

$SIZE_i$ is a continuous variable for the size (in kW) of the PV system installed on the home prior to transaction *i*,[7]

β_1 is a parameter estimate for the quarter in which transaction *i* occurred,

β_2 is a parameter estimate for the census block group in which transaction *i* occurred,

β_3 is a vector of parameter estimates for home and site characteristics *a*,

β_4 is a parameter estimate for the change in sale price for each kilowatt added to a PV system, and

ε_{itk} is a random disturbance term for transaction *i*, in quarter *t*, in block group *k*.

The parameter estimate of primary interest in this model is β_4, which represents approximately the marginal percentage change in sale price over the average sale price of the comparable set of non-PV homes within the same census block group, with the addition of each kilowatt of PV.[8] If differences in selling prices exist between PV and non-PV homes, we would expect the coefficient to be positive and statistically significant.

This model allows an examination of many of the research questions depending on the dataset that is used. If the full dataset is used, the first question can be answered. If a subset of the dataset is used, many of the other questions can be answered. For example, if homes within and outside California are used, the second question can be explored. Similarly, if the data are restricted to particular subsets of the study period (e.g., 2002–2007, 2008–2009, 2010–2011, or 2012–2013), the fourth research question could be examined. To explore if new or existing homes had similar premiums (the fifth question), the data could be restricted to those subsets. Finally, if only PV systems of particular ages were used, the seventh question could be answered. Therefore, almost all of the research questions can be answered using subsets of the data, leaving only the sixth question regarding green cachet, which requires a slightly altered model and will be discussed next, and the third question, which can use either the full dataset or subsets of the data but also requires calculations of comparison valuation estimates using the cost or income method.[9]

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[7] All references to the size of PV systems in this paper, unless otherwise noted, are reported in terms of direct-current watts or kilowatts under standard test conditions. A discussion of this convention is offered in Appendix A of Barbose et al. (2014).

[8] To be exact, the conversion to percent is actually EXP(β_4)-1, but the differences are often *de minimis*.

[9] Although the preferred method is to estimate a separate model using a subset of the data, which allows all of the controlling parameters to take different values for each subset, we also explored estimating models with a categorical variable for each of the subsets interacted with either the variable of interest only <u>or</u> both the variable of interest and the other controlling parameters, with no substantive change in the results.

2.2 Base Model Variation: Size of PV System Model

Although the Base Model and variations to the subsets of data allow examination of almost all the research questions, the sixth question requires a slightly altered model: the Size of PV System Model. If the market exhibits a green cachet, theoretically a fixed amount might be added to the value of a home with PV regardless of the size of that PV system. Therefore, for smaller systems, a premium expressed in dollars per installed watt would be larger than it would be for larger systems, representing a decreasing marginal premium for each watt added to a PV system. To examine decreasing marginal returns, a second-order polynomial is added, and therefore we estimate the following model:

$$\ln(\mathrm{P_{itk}}) = \alpha + \beta_1(\mathrm{T_i}) + \beta_2(\mathrm{K_i}) + \sum_{a} \beta_3(\mathrm{X_i}) + \beta_4(\mathrm{PV_i} \cdot \mathrm{SIZE_i}) + \beta_5(\mathrm{PV_i} \cdot \mathrm{SIZE_i}^2) + \varepsilon_{\mathrm{itk}} \qquad (2)$$

where

SIZE_i^2 is a continuous variable for the squared size (in kilowatts) of the PV system installed on the home prior to transaction *i*, and

β_5 is a parameter estimate for the change in sale price for each additional squared kilowatt added to a PV system, and all other variables are as shown in Equation (1).

The parameter estimates of primary interest in this model are β_4 and β_5. If decreasing marginal returns exist for increasing sizes of PV systems, we would expect the β_4 coefficient to be positive and larger and the β_5 coefficient to be negative and smaller.

2.3 Model Summary

Combining the Base Model, the use of various subsets of data, and the Size of PV System Model allows examination of the seven research questions listed in Section 1. The full set of research questions, models, and sample sets are described in Table 1.

Table 1: Summary of Research Questions, Models, and Sample Sets

Research Question	Equation	Model Name	Sample Set(s)
1. Are PV home premiums evident for a broader group of PV homes than has been studied previously both inside and outside of California and through 2013?	Equation (1)	Base Model	All Data
2. Are PV home premiums outside of California similar to those within California?	Equation (1)	Location Models	CA vs. Non-CA Homes
3. How do PV home premiums compare to contributory values estimated using the cost and income methods?	Equation (1)	Various Models	All Data, or Subsets of Data, But Compare Results To Income and Cost Methods
4. How did the size of the premium change over the study period, as gross PV system prices decreased and during housing market swings?	Equation (1)	Year of Sale Models	Subsets of Years in Sample Period (e.g., Pre-'08; 08-09, 10-11, Post 11)
5. Are premiums for new PV homes similar to existing PV home premiums?	Equation (1)	Home Type Models	New vs. Existing Homes
6. Is there evidence that there is a "green cachet" for PV homes over and above the amount paid for each additional watt added?	Equation (2)	Size of PV System Model	All Data
7. How does the age of the PV system influence the size of the PV premium?	Equation (1)	Age of PV System Models	Subsets of PV System Ages (e.g., < 2 years; 2-4; 5-6; 7-14 years)

2.4 Robustness Models

We also explore the robustness of our results with two alternative model specifications.

2.4.1 PV Only Model

It has been well documented that PV homes often have a suite of additional energy-efficiency (EE) features (CPUC, 2010; Hee et al., 2013; Langheim et al., 2014). Further, it has been theorized that PV home owners, who have the financial resources to install a PV system, might also make other (non-EE) upgrades, such as a new kitchen or bathroom, or may alternatively replace their roof contemporaneously with PV system installation. Therefore, the premium estimated from Equation (1) could also include effects of EE and other features and therefore overestimate the effect related to PV alone.

To test this, PV homes are compared to other PV homes based on system size. While the Base Model estimates a difference in sales prices between PV and non-PV homes, all else being equal, the PV Only Model compares the difference between PV homes and PV homes based on differences in their PV system size, all else being equal. Assuming all PV homes have the same frequency of EE and other features among them, an effect free of those influences can be estimated and then compared to the results in Equation (1).[10]

One complication of this model concerns possible collinearities of the block group fixed effects and PV when a single or small number of PV homes exist within a single block group. While in the Base Model the use of the block group fixed effect is appropriate, because each contains at least one PV and one non-PV home, in the PV Only Model collinearities might exist for block groups with only one or a few PV homes, or those that might have only similarly sized PV systems. In those block groups, the fixed effect might absorb the contributory effect of the PV variable. Therefore, this model uses the county as the fixed effect and is restricted to counties that have two or more PV homes, to allow more heterogeneity between the PV homes within the fixed effect delineation and therefore less collinearity between them and the PV variable; otherwise the model is identical to Equation (1).[11]

2.4.2 Repeat PV Home Model

A common concern with hedonic modeling, such as the Base Model, is that a suite of home and site characteristics are not controlled for, which could be driving the results. These omitted variables could include any manner of home features, such as granite countertops, a newly renovated basement, and Jacuzzi, as well as neighborhood features, such as location on a cul-de-sac, a scenic vista, or location next to a major road. These variables could be present for PV and non-PV homes. Although the assumption is that these unobserved features are randomly distributed among PV and non-PV homes, and therefore are not correlated with the presence of PV, this might not be the case. This can be tested using the Repeat PV Home Model.

The Base Model estimates a difference in sales prices between PV and non-PV homes all else being equal, but the Repeat PV Home Model compares sales prices of homes before they had PV installed to prices of the same homes after they had PV installed. Because many of the characteristics controlled for

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[10] It is at least conceivable that EE and other features are correlated with PV system size, with a larger PV system correlated with more EE and other features. We expect, however, that this would likely be more correlated with the size of the home, which is controlled for in this and the Base Model.

[11] Although not shown here, using county fixed effects in the Base Model in place of block group fixed effects has no apparent effect on the premium estimate, and therefore this PV Only Model can be compared directly to the Base Model results. Also, this model assumes a tradeoff with being able to compare PV homes to PV homes, and therefore controlling for the unobservables associated with PV, versus controlling for the unobservables associated with the localized neighborhood effects that the block group fixed effect controls for.

in the Base Model are held constant in the Repeat PV Home Model, such as block group and size of the home and parcel, they do not need to be controlled for.[12] Therefore, the following greatly simplified model can be estimated:

$$\ln(\mathrm{P}_{\mathrm{itk}}) = \alpha + \beta_1\left(\mathrm{T}_{\mathrm{i}}\right) + \sum_{\mathrm{a}} \beta_2\left(\mathrm{X}_{\mathrm{i}}\right) + \beta_3\left(\mathrm{PV}_{\mathrm{i}} \cdot \mathrm{SIZE}_{\mathrm{i}}\right) + \varepsilon_{\mathrm{itk}} \tag{3}$$

where

X_i is a vector of age of the home and age squared for transaction *i*,

β_2 is a vector of parameter estimates for age and age squared,

β_3 is a parameter estimate for the change in sale price for each additional kilowatt added to a PV system, and all other variables are as defined in Equation (1).

[12] Ideally we would have information on the size of the home as of the first sale <u>and</u> the second sale, but we only have information from the most recent assessment and therefore can only assume that it has not changed between sales. If it has changed, however, it would have likely increased the home's value, thus the second sale would include the increase in related value. If this were the case, the PV premium would capture this increase. Our results do not exhibit this increase, so it is assumed that the Repeat PV Home Model results are free of this influence.

3. Data Preparation and Summary

This section describes the underlying data used for this analysis—including PV home and non-PV home data, cost estimates, and income estimates—followed by a data summary.

3.1 PV and Non-PV Home Data

For the Tracking the Sun (TTS) report series (e.g., Barbose et al., 2013), Lawrence Berkeley National Laboratory was provided a set of approximately 150,000 host-owned (i.e., not third-party-owned) PV home addresses by various state and utility incentive providers, along with information on PV system size, date the incentive was applied for, date the system was put into service, and the average tilt and azimuth of the PV system, where available.[13] These data span the years 2002–2012 and stretch across eight states: California, Connecticut, Florida, Massachusetts, Maryland, North Carolina, New York, and Pennsylvania.[14]

These PV home addresses were matched to addresses maintained by CoreLogic,[15] which CoreLogic aggregates from county-level assessment and deed recorder offices. Once the addresses were matched, CoreLogic provided, when available, real estate information on each of the PV homes as well as similar information on approximately 200,000 non-PV homes located in the same (census) block group as the PV homes. The data for both of these sets of homes included, but were not limited to:

- address (e.g., street, street number, city, state and zip+4 code);
- most recent and previous (if applicable) sale date and amount;
- home characteristics (e.g., acres, square feet of living area, bathrooms, pool, and year built[16]);
- assessed value of land and improvements;
- parcel land use (e.g., commercial, residential);
- structure type (e.g., single-family residence, condominium, duplex); and,
- x/y coordinates.

These data were cleaned to ensure all data were populated and appropriately valued.[17] Using these data, along with the PV incentive provider data, we determined if a home sold after a PV system was installed, significantly reducing the usable sample because the majority of PV homes have not yet sold. We also culled a subset of these data for which previous sale information was available and for which a PV system

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[13] For a full discussion of how these data are obtained, cleaned, and prepared, see Barbose et al. (2013).

[14] The TTS dataset also included data on PV homes from other states, including Illinois, New Mexico, New Hampshire, Oregon, Texas, and Vermont. However, after matching to the CoreLogic sales transaction dataset and cleaning to ensure all the homes that did sell had data that were fully populated and appropriately signed, no PV home sales existed from these states.

[15] More information about this product can be obtained from http://www.corelogic.com/.

[16] Year built, along with previous sales information and a CoreLogic-provided flag on new homes, allowed for a determination of whether the home was newly built or existing at the time of sale.

[17] Because the CoreLogic data sometimes are missing or miscoded, the cleaning and preparation of these data were extensive and therefore not detailed here, but the process included the following screens: sale price greater than $165,000 and less than $900,000, size of the home between 1,000 and 5,000 square feet, sale price per square foot between $8 and $800, sale year after 2001, and size of the parcel between 0.05 and 10 acres.

had not yet been installed as of this previous sale. These "repeat sales" were used in the Repeat PV Home Model described in Section 2.4.2 .

Ideally, for each PV home transaction, we would have a set of identical (i.e., all else being equal) non-PV home transactions for comparison. This theory underlies the comparable-sales method used by appraisers and other valuation professionals (Adomatis, 2014), where comparable homes are chosen that are as similar as possible, and then adjustments are made to account for the observable differences.

To emulate the comparable-sales method, we employed the Coarsened Exact Matching (CEM) process (King et al., 2010), which finds a matched sample of PV and non-PV homes that are statistically equal on their covariates.[18] The covariates include being within the same block group, selling in the same year, and having similar values for size of the home, age of the home, size of the parcel, and ratio of assessed value of land to total assessed value.[19] This procedure results in a reduced sample of homes to analyze, but biases related to the selection of PV and non-PV homes are minimized.[20] The unmatched dataset has 173,982 non-PV homes and 5,373 PV homes, while the matched dataset—the one used for the analysis—has 18,871 non-PV homes and 3,951 PV homes. Various models, as described above, use subsets of the PV homes and therefore will need matching non-PV homes. For most of the subsets this is straightforward, because we divide the PV and non-PV homes along the same lines used for the CEM matching, such as whether the homes are located in California or the rest of the United States, or if they are newly built homes or existing. For the Age of PV Systems models, though, there is not an intuitive division for the non-PV homes, because age of the PV system was not used for matching. Therefore, for these models the CEM process was employed again for each set of PV homes. The resulting matched non-PV homes were not necessarily mutually exclusive between the sets of PV homes, but most importantly each block group contained at least one PV home and one non-PV home.

3.2 Cost Estimates

In this analysis, as in previous studies (Hoen et al., 2011; 2013a; 2013b), we compare the market premiums we find using our Base Model and alternative models to cost and income contributory-value estimates to illuminate how the market might be reacting to various signals. A cost estimate refers to the cost to replace an asset with a new equivalent. Appraisal theory posits that cost estimates are likely important price signals in the marketplace, and market values normally should not exceed the replacement cost of an asset. This might mean, for example, that a buyer of a PV system already installed on a home is not willing to pay more for it than the cost of a new system (i.e., its replacement cost).

For this analysis, we prepared two sets of cost estimates: gross costs and net costs, the detailed preparation of which is described in Appendix A. In this context "net" implies a cost after federal and state tax incentives and state rebates are factored in, while "gross" estimates do not factor these incentives

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[18] The procedure used, as described in the referenced paper, is CEM in Stata, available at: http://ideas.repec.org/c/boc/bocode/s457127.html. Because this matching process excludes non-PV homes that are without a statistically similar PV match (and vice versa), a large percentage of homes (approximately 90% of non-PV and 33% of PV) are *not* included in the resulting dataset. Pre-matching Multivariate Distance (0.95) compares favorably to post-matching Distance (0.82).

[19] The assessed value of land to total value ratio is expected to capture the unexplained within-block group locational variation that often is present, for example, due to being on a quiet road, abutting a park, or being on the waterfront. Assessed values, it is assumed, are consistently applied within the block group.

[20] Although the preferred model is one with a matched dataset, the Base Model was also estimated using the unmatched dataset, which results in a slightly higher estimated premium. We attribute this change to the heterogeneity of the unmatched PV and non-PV homes and the fact that the unmatched non-PV homes have lower-valued unobserved characteristics.

in.[21] We distinguish between the two because the ability of the homeowner to benefit from the incentives depends somewhat on their tax obligations. For example, the federal incentive for PV comes in the form of a reduced federal tax obligation (formally known as the Internal Revenue Code Section 25D: Residential Energy Efficient Property Credit). If a homeowner expects to pay very little in taxes (e.g., because they have a mortgage and very little taxable income), then the federal tax incentive might not be realized immediately (it can be carried over year to year). A similar scenario exists if state tax incentives are present. More generally, incentive availability changes with time, so home buyers may have some uncertainty about what incentives might be available, and their value. Because of these different scenarios, it is not immediately clear if the market would fully capitalize the incentives calculated as part of the net cost, thus net cost can serve as the low cost estimate for our purposes. Similarly, we expect that buyers would not be willing to pay more than the gross cost, which thereby serves as the high cost estimate.

Finally, in previous analyses, we prepared cost estimates depreciated using a straight-line 20-year depreciation schedule, assuming this would be roughly equivalent to the usable life of a PV system (Hoen et al., 2011; 2013a; 2013b). For the present analysis we use, instead, the un-depreciated amount. In doing so, we do not presuppose how the market depreciates PV systems and/or the replacement costs of those systems; rather, we allow the market to dictate how best to depreciate their values, if at all. This is the customary approach of appraisers (Adomatis, 2014).

3.3 Income Estimates Using the PV Value Algorithm

As with cost estimates, appraisal theory posits that income estimates—a discounted stream of income derived from an asset over time, such as rent—are likely important price signals in the marketplace. For example, an apartment seller might not be willing to sell a property for significantly less than the present value of rent (minus costs) it receives for that property. Similarly, the buyer and seller of a home with a PV system might use the discounted value of the system's energy cost savings as a key factor in determining any PV premium.

For each of the PV homes in our sample, we prepared data to estimate the present value of energy bill savings (income estimates) using the size and age of the system, the zip code of the home, and the estimated tilt and azimuth of the system.[22] These inputs were fed through the PV Value algorithm (Klise et al., 2013) to produce estimates for utility bill savings for a similarly sized system as of the time of sale.[23]

The algorithm is outlined by Klise and Johnson (2012), and the inputs for our current research effort are based on the following: the expected energy output of the PV system after the sale date and assuming a life span not greater than the warranty life of the panels (usually 25 years); an electricity retail rate at the time of sale and an escalation of the rate similar to the historical escalation over the previous years; discount rates as of the time of sale, which, for the purposes of this study, are equivalent to 100 basis points above the 30-year, fixed mortgage, 60-day Fannie Mae lock-in rate at the time of sale; a system

[21] Other incentives exist, such as state renewable energy credits, feed-in tariffs, and performance-based incentives, but these are rare throughout the analysis dataset and therefore are not considered. Understanding how to value them appropriately should be the subject of future research, however, because their value can be significant in certain circumstances.

[22] Because tilt and azimuth were not available for all PV systems (the data were not provided during the TTS data-collection effort), they were estimated via a cascading approach, based on systems with those data in the same census block group if available, then, if not available, census tract or, finally, county when needed.

[23] The estimation procedure produces a set of low, average, and high estimates of the present value of the expected energy output, based on a risk premium of 50, 100, and 200 basis points, respectively. Only the average value was used for this analysis.

direct current-to-alternating current derate factor of 0.77%; a module degradation factor of 0.5% per year; and an expected inverter replacement at 15 years. Tiered rates, which are prevalent in California, are not considered here, but instead an average zip-code level rate is used, as is the default for PV Value. We return to this issue in Section 5, where we discuss results from the model estimation in comparison to the income estimates.

The descriptions of the income estimation procedure are contained elsewhere (Klise and Johnson, 2012; Appendix A in Hoen et al., 2013b; Klise et al., 2013) and therefore are not detailed here.

3.4 Data Summary

The final dataset includes 22,822 transactions, consisting of matched PV (*n* = 3,951) and non-PV (*n* = 18,871) homes. This full matched dataset is composed of transactions occurring across eight states (Table 2) from 2002 to 2013 (Table 3), with the vast majority in California. All PV systems in this dataset are homeowner owned as opposed to third-party owned (leased or under a power-purchase agreement).

Table 2: Frequency Summary of PV and Non-PV Homes by State

State	Non-PV Homes	PV Homes	Total
CA	18,207	3,828	22,035
FL	317	25	342
Mid-Atlantic Region: MD, NC, PA	288	77	365
Northeast Region: CT, MA, NY	59	21	80
Total	18,871	3,951	22,822

Table 3: Frequency Summary of PV and Non-PV Homes by Sale Year

Sale Year	Non-PV Homes	PV Homes	Total
2002	107	18	125
2003	196	31	227
2004	238	53	291
2005	197	56	253
2006	348	64	412
2007	818	242	1,060
2008	1,251	453	1,704
2009	1,762	429	2,191
2010	2,751	504	3,255
2011	3,341	642	3,983
2012	3,928	694	4,622
2013	3,934	765	4,699
Total	18,871	3,951	22,822

Summary statistics for the PV and non-PV homes are shown, respectively, in Table 4 and Table 5. The mean sale price (*sp*) of the PV homes in the sample is $473,373 and ranges from a minimum of $165,500 to a maximum of $899,500. The average PV home in the sample has 2,334 square feet of living area (*sfla*), is located on a parcel of 0.45 acres (*acres*), and was 17 years old (*age*) when it sold in 2010 (*sy*).[24] It has a 3.6-kW PV system (*size*), which was installed 2.7 years before the home was sold (*pvage*). The gross installed cost for a similarly sized PV system in the same county at the time of sale was $6.90/W (*grosscost*), while the net cost (after incentives) was $4.14/W (*netcost*). The present value of the stream of energy produced by the PV system, as calculated by the PV Value algorithm, is $2.93/W (*income*). PV systems in the sample range in size from 0.1 kW to 14.9 kW, with a median of 2.8 kW (*size*). The age of the PV systems at the time of sale ranges from new to more than 13 years, with a median of 2.2 years (*pvage*). For the 18,871 non-PV homes, we find a mean sale price of $456,378, which is $16,995 lower than that of the matching PV homes. The average non-PV home is slightly smaller than the average PV home (2,319 square feet), occupies a smaller parcel (0.41 acres), and is equivalent in age. The dataset contains 7,480 newly built homes and 15,342 existing homes, of which 1,444 and 2,507, respectively, are PV homes.

Table 4: Summary Statistics for All PV Homes

variable	description	N	mean	sd	min	median	max
sy	year of sale	3951	2010	2	2002	2011	2013
syq	year and quarter of sale (yyyyq)	3951	20103	23	20021	20111	20134
sp	price of sale (dollars)	3951	$ 473,373	$ 196,451	$ 165,500	$ 433,000	$ 899,500
lnsp	natural log of sale price	3951	12.98	0.43	12.02	12.98	13.71
sfla	living area (square feet)	3951	2,334	702	1,006	2,244	4,981
sfla1000	living area (in 1000s of square feet)	3951	2.3	0.7	1.0	2.2	5.0
acres	size of parcel (in acres)	3951	0.45	0.95	0.05	0.18	9.99
age	age of the home at time of sale (years)	3951	17	21	(2)	7	100
agesq1000	age of the home squared (in 1000s of years)	3951	0.7	1.3	0	0.0	10.0
pv	if the home has a PV system (1 if yes)	3951	1	-	1	1	1
size	size of the PV system (kilowatts)	3951	3.6	2.0	0.1	2.8	14.9
pvage	age of the PV system at time of sale (years)	3951	2.7	2.9	(0.5)	2.2	13.4
income	average PV Value estimate ($/watt)	3951	$ 2.93	$ 0.57	$ 1.18	$ 2.92	$ 4.98
netcost	net cost estimate ($/watt)	3951	$ 4.14	$ 0.93	$ 1.07	$ 4.04	$ 7.95
grosscost	gross cost estimate ($/watt)	3951	$ 6.90	$ 1.50	$ 3.15	$ 6.92	$ 11.83

Table 5: Summary Statistics for All Non-PV Homes

variable	description	N	mean	sd	min	median	max
sy	year of sale	18871	2010	2	2002	2011	2013
syq	year and quarter of sale	18871	20103	23	20021	20112	20134
sp	price of sale (dollars)	18871	$ 456,378	$ 197,004	$ 165,500	$ 413,000	$ 899,500
lnsp	natural log of sale price	18871	12.94	0.44	12.02	12.93	13.71
sfla	living area (square feet)	18871	2,319	714	1,001	2,200	4,990
sfla1000	living area (in 1000s of square feet)	18871	2.3	0.7	1.0	2.2	5.0
acres	size of parcel (in acres)	18871	0.41	0.86	0.05	0.18	9.8
age	age of the home at time of sale (years)	18871	17	21	(2)	8	100
agesq1000	age of the home squared (in 1000s of years)	18871	0.7	1.3	0	0.1	10.0
pv	if the home has a PV system (1 if yes)	18871	0	0	0	0	0

[24] Negative values for the minimum age of a home (e.g., -2) apply to newly built homes in the sample and occur when the sale date is prior to the date of home completion, as might occur when a home is purchased on spec. Similarly, for PV system age, a negative minimum value occurs when the completion date of the PV system occurred before the home sale date, which happens sometimes for new homes. Additionally, although acres is shown in the tables, it is entered in the model as a spline function of up to 1 acre and any additional acres above 1 (see Section 2.1). Finally, age of the home squared is not shown in the tables.

4. Results

This section presents results, starting with the Base Model, which addresses the first research question: Are PV home premiums evident for a broader group of PV homes than has been studied previously? This is followed by results for the various other models, which explore the remainder of the research questions (Table 1 shows the full set of questions), and the two robustness models.

4.1 Base Model Results

The Base Model estimates, over the entire dataset, the marginal return to each kilowatt of PV installed on a home as defined in Equation (1). The model is summarized in Table 6, with full results shown in Table 7.[25] Overall the model performs well, with an adjusted R^2 of 0.92, indicating that it captures approximately 92% of the price variation within the 22,822 home sales located in the 1,830 census block groups that make up the sample.

Table 6: Base Model Results Summary

Total *n*	22,822
PV *n*	3,951
Non-PV *n*	18,871
Adjusted R^2	0.92
Dependent Variable	lnsp
Block Group Fixed Effects	1,830

The full set of results is shown in Table 7. The controlling variables that account for size (*sfla1000*) and age of the home (*age, agesq1000*) and size of the parcel (*lt1acres*, for each acre up to 1, and *gt1acres*, for each acre over 1) are all highly statistically significant (i.e., *p*-value < 0.001). The model indicates that, in our sample, each additional 1,000 square feet adds approximately 21% to the selling price, while each acre up to 1 adds 39% and each additional acre beyond 1 adds 3%.[26] Each year a home ages initially takes approximately 0.7% off its value, but this annual value reduction declines with time, and homes over approximately 60 years in age appreciate in value as they age.[27] Using the fourth quarter of 2013 as the reference category, in our sample, prices start approximately 44% lower (Q1 2002) and then increase to approximately 20% higher (2005), before falling again to lows in early 2012 and then increasing to levels present in late 2013. This rise, fall, and eventual recovery are entirely consistent with the national trends in housing prices.[28] Combined, the various controlling characteristics are appropriately signed and leveled based on our expectations, giving us confidence that the model is acting appropriately and adequately capturing price differences across the sample.

Turning to the variable of interest, *pv*size*, the model estimates that, for each kilowatt of installed PV, sale prices increase by 0.91%, and this estimate is highly statistically significant (*p*-value < 0.001).

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[25] All models are estimated in Stata using *areg*, with block groups as the absorbed fixed effect and with robust standard errors.

[26] The exact percentage interpretation of coefficients in a semi-log model is as follows: exp(coefficient)-1, but the differences in this context are *de minimis*.

[27] Approximately 60 years is determined by dividing the age coefficient by the first derivative of the square term's (*agesq*) coefficient.

[28] As noted previously, we also explored interacting the year of sale with the county, to capture regional price trends, with no substantive change to the results.

Accordingly, at the 95% confidence interval, average price increases are estimated to vary between approximately 0.78% and 1.05% per kilowatt, a relatively precise estimate. This sample of approximately 4,000 PV homes shows a clear premium for each kilowatt of PV installed above the sale prices of comparable non-PV homes.

By using the mean sale price (in dollars) for non-PV homes, we can convert this percentage estimate into dollars per watt.[29] Doing so leads to an estimated premium of \$4.18/W, with a 95% confidence interval of +/- \$0.62/W, which corresponds to a premium of approximately \$15,000 for an average-sized system of 3.6 kW. From Table 4, we see that, for these PV homes, the mean gross cost estimate is \$6.90/W, while the net cost estimate is \$4.14/W, and the average PV Value (income) estimate is \$2.93/W. Therefore, the premium in our sample is almost identical to the average net cost for a similarly sized system as of the time of sale, is approximately \$2.70/W less than the gross cost, and is \$1.25/W higher than the PV Value income estimate.

4.2 Base Model Variations Using Subsamples

As shown in Table 1, many of the research questions can be investigated using variations of the Base Model that use subsamples of the data in place of the full sample. The following sections describe those model sets and include: Location Models, for California and the rest of the United States; Home Type Models, for newly built and existing homes; Age of PV System Models; and Year of Sale Models.

4.2.1 Location Model Results

Our Location Models estimate premiums for either the subset of homes located in California or those located in the rest of the United States; Table 8 shows the results, along with results for the Home Type Models (which are discussed in the next subsection).[30] Also shown in the table, for reference purposes, are the results for the Base Model using the full sample. Results shown for each model include the *pv*size* coefficient, standard error, and *p*-value; the mean non-PV home sale price; the \$/W premium and its 95% confidence interval; and estimates for the net and gross costs and PV Value income. Finally, for each model, the table shows the total, PV, and non-PV sample sizes; the adjusted R^2; and the number of block groups represented by the sample.

The coefficient for the variable of interest for the California subsample is 0.0091, which is highly statistically significant and equates to a \$4.21/W premium and a 95% confidence interval of +/- \$0.64/W. Not surprisingly, the PV premium is very close to the premium estimated for the full sample, because California PV homes make up 97% of that sample. The PV premium can be compared to the net, gross, and PV Value estimates of \$4.16/W, \$6.94/W, and \$2.95/W, respectively.

For homes outside of California where we have data (in Connecticut, Florida, Massachusetts, Maryland, North Carolina, New York, and Pennsylvania), the PV premium is estimated to be \$3.11/W and highly statistically significant (*p*-value < 0.01), but with a 95% confidence interval of \$2.33. This indicates that, in this broader sample of homes, a premium for PV homes is evident, but that the smaller sample of homes outside California does not allow for a very precise estimate of the effect size. The estimated premium is very similar to the net cost estimate for this subset of \$3.09/W, and it is not statistically different from the premium estimated for California homes.

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[29] The formula for doing so is: \$/W premium = ((exp (*pv*size* coefficient)-1)* *mean sale price in dollars for non-PV homes*)/1,000.

[30] For brevity, only the variable of interest is shown for the remainder of the report. Results for the controlling variables were similarly signed and leveled across the various models as they are in the Base Model. The full set of results is available upon request.

Table 7: Base Model Results

Variable	Coefficient	Standard Error	*t* Statistic	*p*-value	- 95% CI	+ 95% CI
intercept	12.498	0.016	758.00	0.000	12.465	12.530
pv*size	0.0091	0.0007	13.12	0.000	0.0078	0.0105
sfla1000	0.213	0.004	51.70	0.000	0.205	0.221
lt1acre	0.386	0.028	13.73	0.000	0.331	0.441
gt1acre	0.029	0.006	5.08	0.000	0.018	0.040
age	-0.007	0.001	-7.86	0.000	-0.008	-0.005
agesq1000	0.056	0.009	6.63	0.000	0.040	0.073
syq						
20021	-0.441	0.034	-13.100	0.000	-0.507	-0.375
20022	-0.379	0.038	-10.060	0.000	-0.453	-0.305
20023	-0.375	0.036	-10.480	0.000	-0.446	-0.305
20024	-0.306	0.073	-4.220	0.000	-0.448	-0.164
20031	-0.087	0.056	-1.560	0.118	-0.196	0.022
20032	-0.077	0.037	-2.050	0.040	-0.150	-0.004
20033	-0.025	0.038	-0.670	0.505	-0.100	0.049
20034	-0.035	0.037	-0.950	0.343	-0.108	0.037
20041	0.001	0.031	0.040	0.972	-0.060	0.062
20042	0.095	0.021	4.430	0.000	0.053	0.137
20043	0.121	0.024	5.120	0.000	0.075	0.168
20044	0.124	0.028	4.340	0.000	0.068	0.179
20051	0.137	0.047	2.910	0.004	0.045	0.230
20052	0.204	0.039	5.170	0.000	0.127	0.281
20053	0.164	0.062	2.640	0.008	0.042	0.285
20054	0.202	0.038	5.340	0.000	0.128	0.276
20061	0.159	0.021	7.710	0.000	0.119	0.200
20062	0.163	0.021	7.900	0.000	0.123	0.204
20063	0.160	0.022	7.300	0.000	0.117	0.203
20064	0.071	0.022	3.240	0.001	0.028	0.114
20071	0.162	0.017	9.700	0.000	0.129	0.195
20072	0.124	0.020	6.170	0.000	0.085	0.163
20073	0.074	0.016	4.580	0.000	0.042	0.106
20074	0.002	0.018	0.100	0.919	-0.034	0.038
20081	0.022	0.016	1.360	0.175	-0.010	0.054
20082	-0.005	0.013	-0.380	0.707	-0.031	0.021
20083	-0.050	0.014	-3.690	0.000	-0.077	-0.023
20084	-0.066	0.014	-4.630	0.000	-0.094	-0.038
20091	-0.113	0.014	-8.070	0.000	-0.141	-0.086
20092	-0.116	0.012	-9.800	0.000	-0.139	-0.092
20093	-0.124	0.012	-10.610	0.000	-0.147	-0.101
20094	-0.120	0.012	-9.700	0.000	-0.144	-0.096
20101	-0.121	0.013	-9.030	0.000	-0.147	-0.095
20102	-0.124	0.012	-10.750	0.000	-0.147	-0.102
20103	-0.144	0.012	-11.660	0.000	-0.168	-0.120
20104	-0.171	0.012	-14.070	0.000	-0.194	-0.147
20111	-0.173	0.011	-15.170	0.000	-0.196	-0.151
20112	-0.189	0.011	-17.360	0.000	-0.211	-0.168
20113	-0.190	0.011	-17.040	0.000	-0.212	-0.168
20114	-0.205	0.011	-18.360	0.000	-0.227	-0.183
20121	-0.212	0.011	-19.000	0.000	-0.234	-0.190
20122	-0.176	0.012	-15.180	0.000	-0.199	-0.153
20123	-0.154	0.011	-13.660	0.000	-0.176	-0.132
20124	-0.123	0.012	-10.220	0.000	-0.147	-0.099
20131	-0.090	0.010	-9.480	0.000	-0.109	-0.072
20132	-0.038	0.009	-4.150	0.000	-0.056	-0.020
20133	-0.009	0.009	-1.000	0.317	-0.027	0.009
20134	--- omitted ---					

Table 8: Location and Home Type Model Results[31]

	All Homes	Location: California	Location: Rest of US	Home Type: New Homes	Home Type: Existing Homes
PV Premium Estimates					
PV*Size Coefficient	0.0091	0.0091	0.0085	0.0084	0.0094
PV*Size Standard Error	0.0007	0.0007	0.0032	0.0012	0.0008
PV*Size *p*-value	*0.000*	*0.000*	*0.009*	*0.000*	*0.000*
Mean Sale Price Non-PV ($)	$ 456,378	$ 459,366	$ 364,854	$ 422,001	$ 476,124
PV Premium ($/watt)	$ 4.18	$ 4.21	$ 3.11	$ 3.58	$ 4.51
95% CI ($/watt)	$ 0.62	$ 0.64	$ 2.33	$ 1.00	$ 0.71
Contributory Value Estimates					
PV Value - Income ($/watt)	$ 2.93	$ 2.95	$ 2.15	$ 3.04	$ 2.86
Net Cost ($/watt)	$ 4.14	$ 4.16	$ 3.09	$ 3.85	$ 4.29
Gross Cost ($/watt)	$ 6.90	$ 6.94	$ 5.64	$ 7.34	$ 6.65
Model Info					
Total *n*	22,822	22,035	787	7,480	15,342
PV *n*	3,951	3,828	123	1,444	2,507
Non-PV *n*	18,871	18,207	664	6,036	12,835
Adjusted R^2	0.92	0.93	0.88	0.97	0.91
Dependent Variable	lnsp	lnsp	lnsp	lnsp	lnsp
Block Group Fixed Effects *n*	1,830	1,721	109	155	1,766

4.2.2 Home Type Model Results

Dividing the data by the type of home, specifically whether the home was newly built or existing at the time of sale, allows examination of the differences between these subgroups. In previous analyses, premiums for existing homes were found to be significantly larger than those for newly built homes, but the sample used was smaller, only for homes in California, only extended through 2009, and included homes with sales prices up to almost $3 million (Hoen et al., 2011; 2013a). The present analysis enables a reexamination of this question by using a sample that is larger, more broadly distributed geographically, has more recent data, and uses homes no more expensive than $900,000.

The results from the Home Type Models that used the new and existing home subsamples are shown in Table 8. New homes have a premium of $3.58/W, while existing homes have a premium of $4.51/W, a difference of approximately $1/W. Both estimates are highly statistically significant (p-values < 0.001) by themselves, but they are not statistically different from each other (difference in coefficients = 0.001, p-value = 0.46; not shown in table). Therefore, we are unable to uncover a difference in premiums between those subgroups with the larger, more geographically diverse and recent dataset. Nonetheless, the differences between these two sets of estimates mimic the different net costs, which are higher for existing homes than for newly built homes.

4.2.3 Age of PV System Model Results

Dividing the full sample into subsamples consisting of four quartiles based on PV system age (0.5–2.4 years, 2.4–3.8 years, 3.8–5.9 years, and 5.9–14 years) allows us to explore if the market accounts for PV system age when valuing PV systems. For this set of quartiles, only existing homes are used, because all

[31] Here, as in other results tables, the numbers of block groups for subsets of data do not always sum to 1,830. This occurs when the block groups are not mutually exclusive between the subsets, e.g., with new or existing homes.

newly built homes have PV systems that are also new. Table 9 contains the results for the full set of existing homes and the four other quartile models. Each of the four quartile models uses a different set of PV homes and a set of non-mutually exclusive CEM matched non-PV homes, to which the PV homes are compared.[32]

The coefficients for each progressively older subset of PV systems are monotonically ordered, going from 0.0123 for the systems 0.5–2.4 years old to 0.0055 for systems 5.9–14 years old. These translate into premiums of $5.90/W for the newest systems and $2.60/W for the oldest systems, with relatively stable 95% confidence intervals of approximately $1.40/W and somewhat decreasing cost and income estimates. Clearly home buyers and sellers place greater value on newer systems than on older systems, all else being equal. Although not shown here, additional models were estimated with additional older age groups (e.g., 10–14 years), but the confidence intervals around those estimates increased such that the results were not any more revealing than what is presented here. In none of the models, however, did we find an estimate close to zero. This seems to indicate that, as systems age, their value flattens out, but additional analysis in future years is needed to understand this trend better.[33]

Finally, it appears that the premiums, as systems age, start well above what would be predicted by the net cost estimates for young systems and then fall well below what would be predicted by the net cost estimates for older systems. This is an artifact of how the net cost estimates are calculated. As discussed in Section 3.2 the cost estimates are prepared without any depreciation and therefore are estimates of a new system. Of course new systems likely would not have the same value as otherwise identical older systems, but knowing the correct amount of depreciation to apply to these estimates is beyond the scope of this work.

[32] As described above, because the characteristics on which the PV homes are matched to the non-PV homes are exclusive of PV system age, the set of non-PV homes (and the block groups in which they are located) are not mutually exclusive across the models, but the same rules apply to these subsets in that for each block group that contains a PV home at least one matched non-PV home is present.

[33] Additionally, we calculated a linear estimate of age of PV interacted with PV system size, which was, not surprisingly, negative and highly statistically significant. Although this reaffirms that increasing age of PV systems is highly correlated with lower premiums, by its very nature it implies that PV systems lose 100% of their value at some point in time. This was calculated to be about 13 years, but it is at the end of our dataset and is not borne out in other tests (e.g., bins shown above, polynomial interactions, and additional binning for older systems). Therefore, we conclude that older systems are of lower value, but not of no value, at least given the age distribution of 0 to 14 years contained in the sample.

Table 9: Age of PV System Model Results

	Existing Homes	Age of PV System Groups 0.5-2.4	2.4-3.8	3.8-5.9	5.9-14
PV Premium Estimates					
PV*Size Coefficient	0.0094	0.0123	0.0113	0.0076	0.0055
PV*Size Standard Error	0.0008	0.0014	0.0014	0.0015	0.0016
PV*Size *p* -value	*0.000*	*0.000*	*0.000*	*0.000*	*0.001*
Mean Sale Price Non-PV ($)	$ 476,124	$ 477,737	$ 474,560	$ 478,634	$ 474,476
PV Premium ($/watt)	$ 4.51	$ 5.90	$ 5.40	$ 3.67	$ 2.60
95% CI ($/watt)	$ 0.71	$ 1.30	$ 1.33	$ 1.37	$ 1.51
Contributory Value Estimates					
PV Value - Income ($/watt)	$ 2.86	$ 3.06	$ 3.03	$ 2.83	$ 2.52
Net Cost ($/watt)	$ 4.29	$ 4.49	$ 4.27	$ 4.24	$ 4.16
Gross Cost ($/watt)	$ 6.65	$ 7.08	$ 6.65	$ 6.54	$ 6.34
Model Info					
Total *n*	15,342	4,398	3,865	4,100	3,607
PV *n*	2,507	633	613	635	626
Non-PV *n*	12,835	3,765	3,252	3,465	2,981
Adjusted R^2	0.91	0.93	0.93	0.92	0.90
Dependent Variable	lnsp	lnsp	lnsp	lnsp	lnsp
Block Group Fixed Effects *n*	1,766	574	504	509	540

4.2.4 Year of Sale Model Results

Because the dataset spans the period from 2002 through 2013, we can examine how premiums change over time. This is especially interesting given that, in the same period, the costs for PV modules dropped (Barbose et al., 2013) and housing market prices saw a rapid rise, fall, and recovery. We break the data into four subsamples roughly consistent with these broad changes (2002–2007, 2008–2009, 2010–2011, and 2012–2013) and estimate the Base Model specification for each subsample.

Results from these models are contained in Table 10. The model results for the full dataset are also contained in Table 10 for reference. In each model, the coefficient of the variable of interest, *pv*size*, is highly statistically significant (*p*-value ≤ 0.001), with relatively stable standard errors ranging from 0.002 to 0.001, or a tenth of a percent. Despite varying levels of non-PV homes prices, which range from $512,170 to $440,495, premiums are relatively stable, ranging from $3.41/W to $4.54/W, with none being statistically different from each other over the various periods.

During this period, we see mean gross costs descend from a high of $8.97/W in 2002–2007 to a low of $5.45/W in 2012–2013. Net costs fall much less between these two periods, from $5.39/W to $3.58/W, while PV Value income estimates remain near, or slightly below, $3/W. Despite falling gross costs, and shifts in the overall housing market, premiums remain fairly flat and not statistically different from the net costs in all periods and from the PV Value income estimates in two out of four periods.

Table 10: Year of Sale Model Results

	All Homes	Year of Sale Groups 2002-2007	2008-2009	2010-2011	2012-2013
PV Premium Estimates					
PV*Size Coefficient	0.0091	0.0066	0.0103	0.0083	0.0093
PV*Size Standard Error	0.0007	0.0020	0.0016	0.0011	0.0010
PV*Size *p*-value	*0.000*	*0.001*	*0.000*	*0.000*	*0.000*
Mean Sale Price Non-PV ($)	$ 456,378	$ 512,170	$ 440,495	$ 448,976	$ 453,988
PV Premium ($/watt)	$ 4.18	$ 3.41	$ 4.54	$ 3.73	$ 4.23
95% CI ($/watt)	$ 0.62	$ 2.03	$ 1.34	$ 0.97	$ 0.88
Contributory Value Estimates					
PV Value - Income ($/watt)	$ 2.93	$ 2.79	$ 2.73	$ 3.00	$ 3.02
Net Cost ($/watt)	$ 4.14	$ 5.39	$ 4.56	$ 4.00	$ 3.58
Gross Cost ($/watt)	$ 6.90	$ 8.97	$ 8.25	$ 6.88	$ 5.45
Model Info					
Total *n*	22,822	2,368	3,895	7,238	9,321
PV *n*	3,951	464	882	1,146	1,459
Non-PV *n*	18,871	1,904	3,013	6,092	7,862
Adjusted R^2	0.92	0.96	0.96	0.95	0.91
Dependent Variable	lnsp	lnsp	lnsp	lnsp	lnsp
Block Group Fixed Effects *n*	1,830	259	313	630	1,022

4.3 Size of PV System Model

To examine if larger PV systems garner an equal, lower, or higher marginal price premium than smaller systems, we estimate a polynomial model as described in Equation (2) with parameters for *pv*size* and *pv*size*^{2}. Abbreviated results from this model are shown in Table 11. Coefficients for the first- and second-order polynomials are highly statistically significant (p-value < 0.02) and indicate decreasing marginal returns to increasing PV system size. The *pv*size* coefficient equates to a premium of $5.86/W, while the *pv*size*^{2} coefficient corresponds to a decrease in value of $0.53/W. Therefore, the model estimates that, up to approximately 10 kW, each increase in PV system size adds value to a home, but progressively less value for each addition. Beyond 10 kW, premium increases with increasing system size seem to flatten out, but we are less confident of the results because of the relatively few observations in this size range.[34]

[34] We also estimated models using subsets of data, each containing progressively larger systems, and find a similar pattern, with decreasing $/W premiums for increasing sizes.

Table 11: Size of PV System Model Results

	PV*Size	PV*Size^2
Coefficient	0.0128	-0.0006
Standard Error	0.0015	0.0002
p -value	0.0000	0.0130
Mean Sale Price Non-PV ($)	$ 456,377	$ 456,377
PV Premium ($/watt)	$ 5.86	$ (0.53)
95% CI ($/watt)	$ 1.35	$ 0.42
Model Info		
Total *n*	22,822	
PV *n*	3,951	
Non-PV *n*	18,871	
Adjusted R^2	0.92	
Dependent Variable	lnsp	
Block Group Fixed Effects *n*	1,830	

4.4 Robustness Models

The various models estimated above, which mostly are based on the Base Model and subsets of the data, compare PV home prices to non-PV home prices. Here we estimate two Robustness Models, which allow us to examine the robustness of the results under alternative specifications: the PV Only Model and the Repeat Sales Model. The PV Only Model compares selling prices of only PV homes, while the Repeat Sales Model examines the selling prices of the same home for homes sold once before the PV system was installed and again after it was installed, as described by Equation (3). These models use both different sets or subsets of the data and different specifications of the model, which allows them to control for possible specification biases in the Base Model. They, therefore, serve as valuable comparisons to and, potentially, validations of the Base Model results.

4.4.1 PV Only Model

Results for the PV Only Model are shown in Table 12. The coefficient for *pv*size* is effectively identical to that estimated for the Base Model with the full dataset, and it is highly statistically significant (*p*-value ≤ 0.001). The fact that the coefficient is identical to the Base Model coefficient is remarkable given that it is derived from a model that uses county fixed effects, rather than the more geographically precise block group fixed effect used in the Base Model. The estimated premium is $4.37/W, although the 95% confidence interval is considerably larger at $2.62/W vs. the Base Model's $0.62/W, indicating considerably less precision in the PV Only Model estimate.

4.4.2 Repeat PV Home Model

Results from the Repeat PV Home Model are also shown in Table 12. The coefficient for *pv*size* is very similar to that estimated for the Base Model with the full dataset, but it is not statistically significant (*p*-value = 0.113). The estimated premium is $4.60/W, which is also very similar to that of the Base Model, although the 95% confidence interval, at $5.69/W, is considerably larger than those for the Base and PV Only Models.

4.4.3 Summary of Robustness Checks

Because of the large margins of error, we cannot say the three estimates are statistically different from each other. Despite this, none of the results appear markedly different from that estimated using the Base

Model where PV homes are compared to non-PV homes. When comparing PV homes to other PV homes, as in the PV Only Model, or the same PV home to itself over multiple transactions, as in the Repeat PV Home Model, we find little evidence to support the claim that the Base Model PV premium estimate is biased. Therefore, there appears to be no evidence that the PV estimate also contains the effects of other omitted features such as EE upgrades.

Table 12: Robustness Model Results

PV Premium Estimates	**All Homes**	**PV Only**	**Repeat**
PV*Size Coefficient	0.0091	0.0092	0.0087
PV*Size Standard Error	0.0007	0.0028	0.0055
PV*Size *p*-value	*0.000*	*0.001*	*0.113*
Mean Sale Price Non-PV ($)	$ 456,377	$ 474,529	$ 528,368
PV Premium ($/watt)	$ 4.18	$ 4.37	$ 4.60
95% CI ($/watt)	$ 0.62	$ 2.62	$ 5.69
Contributory Value Estimates			
PV Value - Income ($/watt)	$ 2.93	$ 2.93	$ 2.15
Net Cost ($/watt)	$ 4.14	$ 4.14	$ 3.09
Gross Cost ($/watt)	$ 6.90	$ 6.91	$ 5.64
Model Info			
Total *n*	22,822	3,915	1,698
PV *n*	3,951	3,915	849
Non-PV *n*	18,871	-	849
Adjusted R^2	0.92	0.68	0.23
Dependent Variable	lnsp	lnsp	lnsp
Fixed Effects *n*	1,830	65	n/a

5. Discussion of Research Questions

This section explores in more detail the seven research questions listed in Table 1, building on the full set of results described above.

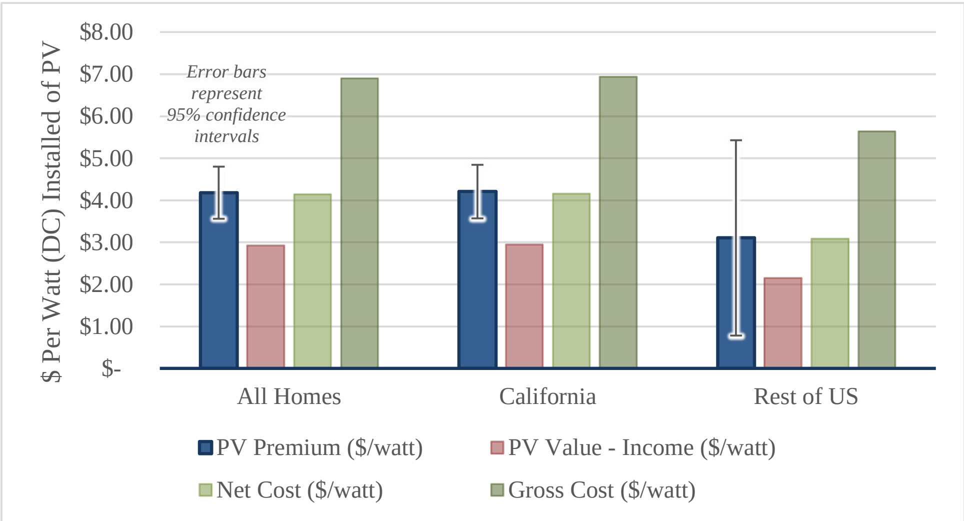
Are PV home premiums evident for a broader group of PV homes than has been studied previously both inside and outside of California and through 2013?

PV home premiums have been found by previous research of transactions of 15 PV homes in one California subdivision from 2001–2006 (Farhar and Coburn, 2008), of 594 PV homes in the San Diego and Sacramento metro areas between 1997–2010 (Dastrup et al., 2012), of approximately 1,900 PV homes in 31 California counties between 1999–2009 (Hoen et al., 2011; 2013a), and of 30 PV homes in the Denver metro area between 2011–2013 (Desmarais, 2013).

This analysis more than doubles the number of transactions analyzed, with data on almost 4,000 PV home transactions across 102 different counties in eight different states, including California, Connecticut, Florida, Massachusetts, Maryland, North Carolina, New York, and Pennsylvania. The data span the period from 2002 to 2013, with more than a third from 2012 and 2013 alone.

The Base Model and Location Models (Table 8 and Figure 1) show a consistent difference in PV home prices compared to matched non-PV homes across the dataset, with premiums ranging from a bit more than $4/W in California to approximately $3/W outside of California, both of which are highly statistically significant.[35] Moreover, this premium, as shown in the Year of Sale Models (Table 10 and Figure 2), survived both the dramatic decrease in installed costs over the study period as well as the market tumult which was the housing bubble, subsequent crash, and recovery. Clearly buyers of homes with PV are willing to pay a premium for PV, and this trend has continued despite dramatic changes in both the PV and housing markets. Finally, similarly sized premiums are found for the two robustness models—the PV Only Model and the Repeat PV Home Model—which further validates these results.

Figure 1: Base and Location Model Results



[35] The standard error for the Base Model of 0.0007 is 35% of the standard error found in the previous analysis of California PV homes of 0.0018 (Hoen et al. 2011; 2013a), indicating the increased precision of this estimate.

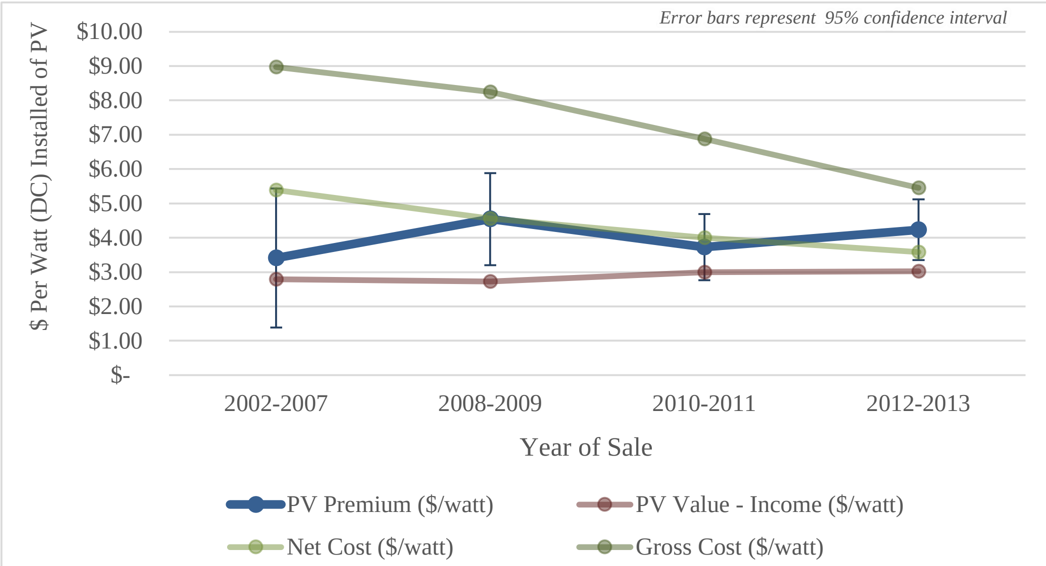
Are PV home premiums outside of California similar to those within California?

As shown in Table 8 and Figure 1, premiums for PV homes are estimated, on average, to be $1.10/W larger in California than outside of California. However, this difference, given the relatively large margin of error around the Rest of U.S. estimate, is not statistically significant. That notwithstanding, the apparent difference seems to echo decreases in each of the three other contributory value estimates we derived. For example, the gross and net costs in California are $1.30/W and $1.07/W higher than outside of California. Similarly, the PV Value income estimate is $0.80/W lower outside of California. In any case, these findings should give stakeholders outside of California greater confidence that PV adds value to homes in their markets.

How do PV home premiums compare to contributory values estimated using the cost and income methods?

The market premiums estimated from our suite of models seem to follow, at least to some degree, the contributory-value net cost estimates and, to a lesser degree, the PV Value estimates using the income approach, but not the gross cost estimates. For example, as shown in Figure 1, both the California and Rest of U.S. estimates are within a few pennies of the net cost estimates, but they are more than $2.50/W less than the gross cost estimates. Similarly, the Year of Sale Model results show PV premiums that are not statistically different in any period from the net cost estimates (Table 10 and Figure 2) despite widely changing gross cost estimates and underlying housing market tumult. Therefore, the net cost estimates—which account for the federal, state, and local incentives available at the time of sale—seem reasonably related to the value added (PV premiums) at least among average PV systems in our sample. Since the data indicate that, for the average systems in our sample, the PV premium is similar to the net cost estimate, it is reasonable to conclude the incentives are offsetting the influence of depreciation for those systems. At the same time and as discussed in further detail later, net cost estimates diverge from the calculated market premiums for those PV systems that are considerably newer or considerably older at the time of home sale. Depreciation in PV premiums is therefore apparent when other PV system ages are considered. As such, adjustments to net cost estimates may be required to account for market-derived depreciation. In this instance, it may be necessary for appraisers to estimate physical deterioration and functional obsolescence in situations where replacement costs exceed the contributory market value of older systems.

Figure 2: Year of Sale Model Results



Curiously, the PV Value income estimates are consistently lower than the premiums found in the market, while theory holds that cost savings should be a strong price signal. One reason for this disparity, which is especially evident in the California subset, might be related to the PV Value inputs that we used in this study, which were based on the average retail electricity rate. In California, tiered volumetric rates, which are based on the customer's consumption, are normal for most of the state's residential PV customers (CPUC, 2013). If customers consume more than the average retail customer, then they will be moved into higher-priced tiers. These tiers can be dramatic, with a doubling or even tripling of rates, depending on which tier the consumer falls into (CPUC, 2013). PV customers tend to be larger consumers of electricity than the average retail customer in California, thus they often pay more than the average (Darghouth et al., 2011; CPUC, 2013) and, with a PV system, may avoid higher-cost tiers altogether, increasing the value of the avoided costs. We cannot determine the exact level of this increase for the specific PV homes in our sample, but even a $0.05/kWh increase in the rate, which is well within the range proposed by others for PV customers (CPUC, 2013), would result in a substantial increase in the income estimate. The mean default electricity rate we entered into PV Value for the California portion of our sample is $0.1543/kWh. If that rate increased by $0.05/kWh, it would increase the PV Value estimate from $2.93/W to almost $4/W, within the margin of error of our premium estimate. Therefore, it seems possible that buyers and sellers might be using the cost savings as an important price signal, but they are estimating those savings at a slightly higher rate than the tool's default average retail rate. It is recommended that, when tiered rates are present that deviate substantially from the default average rate and normal consumption for a particular home would put the homeowner in higher tiers, users of the PV Value tool should input a custom rate that is more appropriate.[36]

How did the size of the premium change over the study period, as gross PV system prices decreased and during housing market swings?

While gross costs decreased dramatically over the study period, dropping 40% from $8.97/W in the 2002–2007 period to $5.45/W in the 2012–2013 period, PV premiums remained fairly consistent around

[36] For example, for California customers where tiered rates are common, weighting based on the tiers and the usage within each tier for particular PV homes might result in a more appropriate input rate.

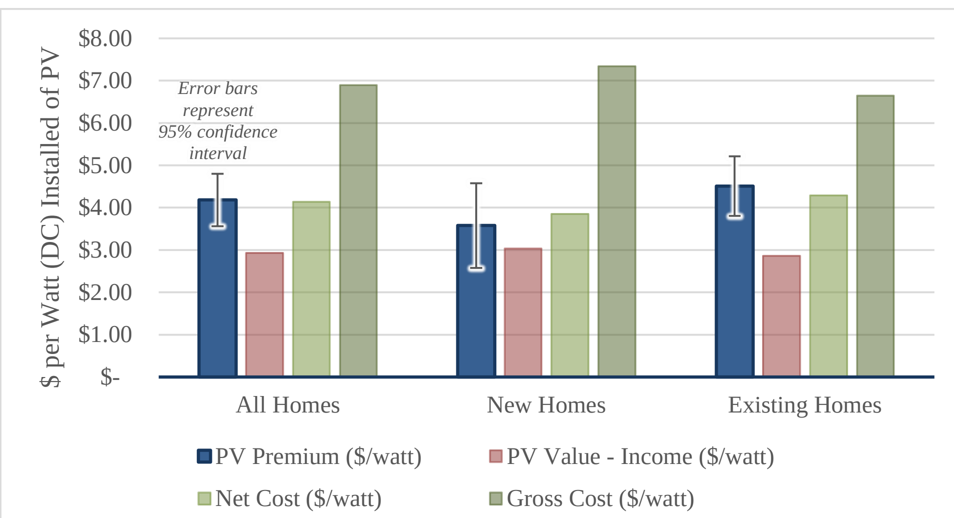
$4/W (see Figure 2). During this same period, the housing market was in upheaval, with a sizable rise, a subsequent crash, and then a recovery. This seems to show, first, that the gross cost is not a strong market signal. Rather, net cost, which over all periods was not statistically different from the premium, seems to be the more significant price signal. Moreover, it shows that the PV premium has been reasonably consistent during widely varying housing market conditions.

Are premiums for new PV homes similar to existing PV home premiums?

The results from the Home Type Model, which explores differences between new and existing home premiums, are shown in Table 8 and Figure 3. The average new home premiums of $3.58/W are lower than the existing home premiums of $4.51/W, a non-statistically significant difference of $0.93/W (*p*-value = 0.46). The net cost estimates for new homes are also lower (by $0.44/W) than those of existing homes, potentially explaining some of the difference.

Previous analyses found large, statistically significant differences between new and existing home premiums (Hoen et al., 2011; 2013a; 2013b). These differences occurred because existing home estimates were larger (near $6.50/W) and new home estimates were smaller (near $2.5/W) than found in the present analysis. It appears, based on analysis not shown here, that high-priced homes (e.g., over $1 million), which were included in the past analyses (up to $3.3 million) but excluded from this analysis, might explain a large portion of the differences. Including those homes in our analysis increased the existing home premiums and lowered the new home premiums, although not to the extent found previously. Including these homes also increased the margin of error around the estimates, however, implying that our models did a poorer job of explaining price differences and that many home and site characteristics for these homes likely are not included in the models. Further, the previous analyses included home transactions only through 2009, but this analysis included transactions through 2013, with two thirds occurring after 2009. In summation, this analysis is likely a better representation of the current market for most PV homes because it included many more recent sales, had more sales in total, and excluded high-priced homes (over $1 million) that were difficult to model, but it does not find a statistically significant difference between new and existing homes.

Figure 3: Home Type Model Results



One additional nuance to the present findings involves the new home premium and the net cost estimate. As discussed in Section 3.2, the net cost estimates (e.g., shown in Figure 3) represent the gross cost estimates less the appropriate federal and state incentives (and rebates where appropriate). The federal incentive, which normally comes in the form of an investment tax credit (ITC), is calculated as 30% of the gross cost of a PV system after state and utility incentives are applied. Interestingly, this incentive cannot be claimed by new home builders but instead only by the buyer of the home.[37] Therefore, the new home buyer not only receives the PV system on the home, but will also be able to receive a tax credit. Correspondingly, the net cost of the builder should not include this federal ITC reduction and, therefore, should be approximately $1.26/W higher and should affect the premium the buyer paid. This is interesting because we do not see a premium that reflects this incentive. If we did, the premium would be approximately $1.26/W higher or $4.84/W; instead we find a premium of $3.58/W.[38] Understanding the exact reasons for this discounting is beyond the scope of this work, but several plausible explanations exist: home builder discounting—the builder discounts the home for other reasons, for example to sell the home more rapidly (e.g., Dakin et al., 2008; SunPower, 2008), which has the effect of obscuring the premium related to the federal ITC; buyer discounting—the buyer is not willing to pay the full cost of the tax credit because it cannot be claimed until the following year when taxes are filed and might not be able to be claimed fully because of a lack of tax appetite by the homeowner; and lack of market clarity—because tax rules related to the federal ITC only recently were clarified (US IRS, 2013), both the home builder and buyer might not have consistently known if the ITC could be claimed.

Is there evidence of a "green cachet" for PV homes above the amount paid for each additional watt added?

Results from the Size of PV System Model suggest that the systems with the highest marginal premiums, in terms of dollars per watt, were the smallest systems, and as system size increased the dollar-per-watt premium decreased (Table 11). This decreasing slope is estimated in Figure 4 for PV systems from 1 to 10 kW, which shows both the decreasing dollar-per-watt value of each additional kilowatt added (left axis) and the total PV system premium (right axis). This indicates, potentially, that there is a fixed component of PV home premiums that occurs regardless of system size. This might indicate that a green cachet exists for PV homes in our sample. In other words, buyers might be willing to pay something for having any size of PV system on their homes and then some increment more depending on the size of the system. These findings echo those found previously (Dastrup et al., 2012).

How does the age of the PV system influence the size of the PV premium?

The results from the Age of PV System Models, which explore how premiums change as PV systems age, are shown in Table 9 and Figure 5. For systems installed on homes just before they were resold, larger premiums were garnered, with premiums falling by almost 60% in the oldest age group compared with the newest group.[39] This indicates that the market quickly depreciates PV systems in their first 10 years at a rate exceeding an average rate of PV efficiency losses, e.g., 0.5%/year (Dobos, 2014), and also exceeding the depreciation expected were straight-line depreciation applied over the asset's life; this might indicate functional obsolescence setting in. Because the mean age for the oldest quartile (5.9–14 years) is only 7.8 years (Figure 5), however, we cannot describe PV system values as they age into their second decade. Does their value level out and decrease at the rate of system degradation? Or do they lose 100% of their value before that? Those questions are recommended for future analyses.

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[37] In this instance we are referring to the federal ITC under Title 26 Section 25D of the Internal Revenue code (see: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F).

[38] The portion of the difference between net and gross cost attributable to the federal ITC ranges from approximately $0.80/W to as high as $1.84/W, with a mean of $1.26/W.

[39] Although not shown here, the average size of PV systems was very similar in all four age bins, at approximately 4.2 kW. We hypothesize that this larger premium for nearly new systems is related to additional nearly new features installed coincidently or the homeowner not fully taking advantage of tax incentives if they had planned on selling the home soon after the installation.

Figure 4: Estimated Dollar Per Watt Premium for Increasingly Larger PV Systems

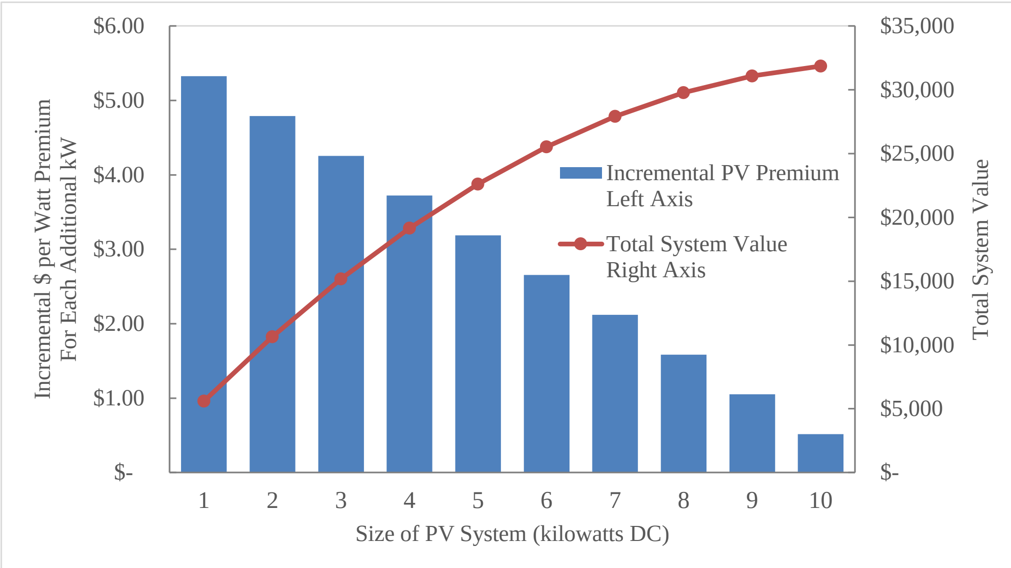
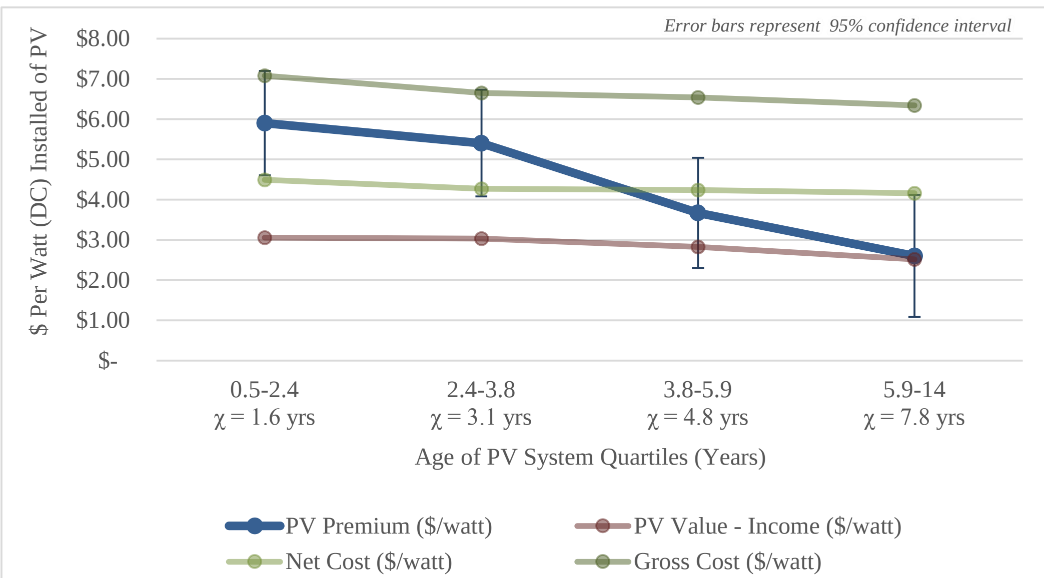


Figure 5: Age of PV System Model Results



6. Conclusion

As solar photovoltaic (PV) systems become an increasingly common feature of U.S. homes, the ability to value homes with these systems appropriately will become increasingly important. The U.S. Department of Energy estimates that achieving its SunShot PV system price-reduction targets could result in 108 GW of residential rooftop PV installed by 2050—equivalent to 30 million American homes with PV (US DOE, 2012).[40] Conversely, capturing the value of PV to residential properties is important for enabling a robust rooftop PV market.

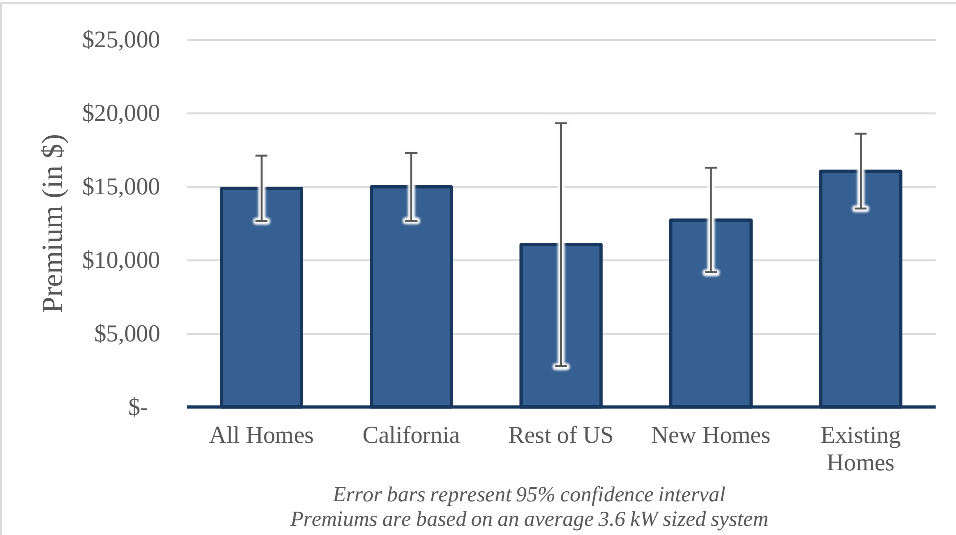
Appraisers, sales agents, and others tasked with property valuation have made strides toward valuing PV homes, and several limited studies suggest the presence of PV home premiums, particularly in California. Our study fills important gaps in this literature and illuminates various factors that might influence U.S. PV home premiums. The study more than doubles the number of PV home sales previously analyzed, examines transactions in eight different states, and spans the years 2002–2013, thus encompassing the recent housing boom, bust, and recovery. Based on our results, we draw the following major conclusions:

- Home buyers consistently have been willing to pay more for a property with PV across a variety of states, housing and PV markets, and home types. Average market premiums across the full sample of homes analyzed here are about $4/W or $15,000 for an average-sized 3.6-kW PV system (Figure 6).
- Our findings should provide greater confidence that PV adds value to non-California homes. Premiums for PV homes are $1.10/W larger in California than outside of California (respectively equating to $16,000 and $12,700 for an average-sized system – Figure 6), but this difference is not statistically significant: somewhat lower premiums outside of California are consistent with lower net cost and income estimates.
- Net cost estimates—which account for government and utility PV incentives—seem to be generally consistent with incremental market value premiums for the average PV home in our sample, but they do not appear to account accurately for market-based depreciation (the difference between value and cost). PV Value income estimates—which for this study used the default average retail rates—were consistently lower than the calculated market premiums, which seems to indicate that a higher retail rate would be more appropriate for that portion of the sample where tiered rates were present.
- PV premiums remained fairly consistent even as PV gross costs decreased dramatically over the study period and the housing market went through upheaval. This suggests that net cost, rather than gross cost, may be the more dominant market signal. It also suggests that PV premiums are robust to housing market conditions.
- In contrast to previous studies, our study found a relatively small and non-statistically significant difference between PV premiums for new and existing homes (respectively equating to $12,700 and $16,000 for an average-sized system – Figure 6), likely because our study includes many more sales and recent sales while excluding very-high-priced homes. That notwithstanding, there might be some evidence of either home builder or buyer discounting of new home PV systems.
- A green cachet might exist for PV homes; that is, buyers might be willing to pay a certain amount for having any size of PV system on their homes and then some increment more depending on the size of the system.
- The market appears to depreciate PV systems in their first 10 years at a rate exceeding the rate of PV efficiency losses and of straight-line depreciation over the asset's life. Our data do not allow analysis

[40] Assuming the average PV system size of 3.6 kW found for all PV homes in this study.

of depreciation into the second decade of PV systems' operation—this is an area for future research.

Figure 6: Estimated Premiums Based on an Average-Sized 3.6 kW System



This study focuses only on homes with host-owned PV systems, as opposed to those with leased PV systems. Future analysis should focus on leased systems, because they are a growing portion of the PV home market and have not been studied. In addition, although our sample indicates that, as PV systems age, the size of the premium diminishes, our data are not robust to systems in their second decade; such older systems should be the focus of future study, as should the appropriate deprecation to place on PV systems throughout their lives.

Although this work allows for a robust analysis of average system premiums across the full dataset, and subsets of the data, the results are not necessarily applicable to individual markets and states that might have unique characteristics. Therefore, any market-specific ("small scale") analysis, especially one that employs appraisers and other valuers in those local markets, would be beneficial. Similarly, collecting and analyzing more data in a wide variety of states individually would be useful.

Because premium differences related to the availability of PV homes are unclear, investigating both buyer's markets (with many PV homes available) and seller's markets (with few PV homes available) would add clarity to PV home valuation. Finally, very large PV systems and systems on commercial properties were not represented in our data; both could have unique valuation characteristics and are thus areas for further study.

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8. Appendix A: Cost Estimate Preparation

To calculate both the net and gross cost estimates for each of the PV home transactions at the time of sale, we estimate a two-stage regression as used previously (Hoen et al., 2011; 2013a; 2013b). This procedure starts with the extensive dataset of more than 150,000 PV homes collected for TTS VI and their respective gross installed costs as reported (Barbose et al., 2013), for which the respective net installed costs (i.e., net of federal and state incentives) are calculated using the procedure outlined in Appendix C of Barbose et al. (2010). The first stage uses the net costs as the dependent variable and county, year, system size, and home type (new or existing) as the independent variables, in the following model:

$$C_{itsc} = \alpha + \beta_1 (T_i) + \beta_2 (S_i) + \beta_3 (N_i) + \beta_4 (C_i) + \varepsilon_{itsc} \tag{4}$$

where

C_{itsc} is the "net installed cost" of PV system *i* after state and federal incentives from the full TTS dataset,

T_i is a vector of variables representing the year *t* in which the system was installed,

S_i is a vector of variables representing the size *s* of the system in rounded kilowatts (e.g., 1 kW, 2 kW, 3 kW…),

N_i is a fixed-effect variable indicating if the home was newly built when the system was installed,

C_i is a vector of variables representing the county *c* in which the system was installed,

α is the constant,

$\beta_{1\text{-}4}$ are coefficients for the parameters, and

ε_{itsc} is the error term.

The model accounts for the different state incentives and system component prices over the study period (via T_i), economies of scale (via S_i), different installed costs between new and existing homes (N_i), and the variety of rate structures, installer competitive prices, and market development (via C_i).

Using the predicted coefficients from this model, the data for the set of PV home transactions (county in which the home is located, PV system size, if the home is newly built, and substituting the sale year for the installation year *t*) are fed into the model to produce predicted net cost estimates. These represent, as of the time of sale, the approximate cost to replace a similarly sized system new on the same home.

An identical procedure is followed for gross cost estimates, except, for the first stage, C_{itsc} is the "gross installed cost" of PV system *i* before state and federal incentives from the full TTS VI dataset.

Tab 5

Presentations

FLORIDA ASSOCIATION OF COUNTIES
All About Florida

November 9, 2015

Amy J. Baker, Coordinator
Legislative Office of Economic and Demographic Research
111 West Madison Street, Suite 574
Tallahassee, FL 32399

Dear Ms. Baker:

This statement is on behalf of the Florida Association of Counties in response to the Financial Impact Estimating Conference inquiry related to the petition initiative entitled **"Rights of Electricity Consumers Regarding Solar Energy Choice".**

The proposed solar energy constitutional amendment seeks to establish a right for consumers to own or lease solar equipment installed on their property to generate electricity for their own use. Additionally, the amendment clarifies that state and local governments shall retain their abilities to protect consumer rights, public health, safety and welfare, and ensure that consumers who choose not to install solar on their property are not required to subsidize the costs of access to backup power and electric grid to those who do.

Initial discussions among the Florida Association of Counties staff have indicated that should the amendment pass, it would not have a significant impact on county revenues.

Sales & use tax (State & Local): Self-generated electricity is taxable; however, the revenue generated by this depends on the customer's voluntary compliance. If an individual sells self-generated electricity to a utility company through a net metering agreement, it is not taxable. If an individual sells electricity to a non-utility entity the sell is taxable.

Franchise Fees: The amendment does not change the status quo which would not jeopardize Franchise Agreements revenues from utility companies.

Ad Valorem: The amendment would not have an effect on ad valorem revenue from residential property. Current law states that

"In determining the assessed value of real property used for residential purposes, an increase in the just value of the property attributable to the installation of a renewable energy source device may not be considered" F.S. 193.624(2). At current millage rates, the installation of solar in non-residential property could have a short run positive impact to counties.

If you have any questions, please contact Orlando Garcia (850)922-4300 ogarcia@fl-counties.com.

Sincerely,

Orlando Garcia
Legislative Analyst

Proposed Citizen Initiative
Amendment 15-17

Title: *Rights of Electricity Consumers Regarding Solar Energy Choice*

Summary: *This amendment establishes a right under Florida's constitution for consumers to own or lease solar equipment installed on their property to generate electricity for their own use. State and local governments shall retain their abilities to protect consumer rights and public health, safety and welfare, and to ensure that consumers who do not choose to install solar are not required to subsidize the costs of backup power and electric grid access to those who do.*

Sponsor: *Consumers for Smart Solar*
2640-A Mitcham Drive
Tallahassee, FL 32308-0000
Jim Kallinger, Chair

General Description:

The operative language of the proposed amendment is as follows: "Electricity consumers have the right two own or lease solar equipment installed on their property to generate electricity for their own use. State and local governments shall retain their abilities to protect consumer rights and public health, safety and welfare, and to ensure that consumers who do not choose to install solar are not required to subsidize the costs of backup power and electric grid access to those who do." The effect of the amendment will be to ensure that certain existing consumer rights and protections with regard to solar energy choices are maintained, even if new approaches to solar electricity are adopted, either now or in the future.

Financial Impact Statement to advocate:

The amendment will have no effect on State and local revenues. The effect of the amendment on the costs to be incurred by State and local governments is minimal, or alternatively, cannot be determined.

Further explanation:

There is nothing now in the Constitution that explicitly addresses the rights of consumers to own or lease solar equipment installed on their property to generate electricity for their own use. Although consumers now can own or lease solar equipment installed on their property to generate electricity for their own use, the right to do so exists by implication or because doing so is not expressly prohibited.

The amendment explicitly codifies in the Constitution the rights of consumers to own or lease solar equipment installed on their property to generate electricity for their own use in order to prevent those rights from being diminished by State or local government action. Because the amendment creates an explicit right in the Constitution, but does not compel any particular State or local government action, the amendment will not increase or decrease State and local government revenues from what they would have been without the amendment.

The amendment does not create a new class of energy producers or tax payers that will collect, remit and/or pay state and local taxes and fees. The amendment also will not by itself impact the revenues of electric utilities upon which various state and local taxes and fees are imposed.

The amendment does not compel any particular course of regulatory action by State and local governments. Rather, by explicitly preserving in the Constitution the full authority of the State to regulate solar, the amendment ensures that State and local government entities retain their powers to protect the health, safety and welfare of the public. Thus, the amendment should not, by itself, cause State and local governments to incur implementation or compliance costs. Although State and local governments may exercise the consumer protection authority preserved by this amendment in the future, it is impossible to predict the nature, extent or timing of those actions. The costs of future actions by State and local governments should not be attributed to this amendment, or if they are, the magnitude of those costs cannot be determined at this time.

Tab 6

Impact