**Welcome to tonight's City Council meeting!**

The elected officials of the City of Bonners Ferry are appreciative of an involved constituency. Testimony from the public is encouraged concerning issues when addressed under the Public Hearing portion of the agenda. Any individual who wishes may address the council on any issue, whether on the agenda or not, during the Public Comments period. Normal business will preclude public participation during the business portion of the meeting with the discretion left to the Mayor and Council.

**Vision Statement**

Bonners Ferry, "The Friendliest City", strives to achieve balanced growth, builds on community strengths, respects natural resources, promotes excellence in Government, and values quality of life.

**AGENDA**
**CITY COUNCIL MEETING**
**Bonners Ferry City Hall**
**7232 Main Street**
**267-3105**
**April 21, 2015**
**7:00 p.m.**

**PLEDGE OF ALLEGIANCE**

**PUBLIC HEARING**

**PUBLIC COMMENTS**

Each speaker will be allowed a maximum of five minutes, unless repeat testimony is requested by the Mayor/Council

**GUESTS**

Chamber of Commerce – Kootenai River Days

**REPORTS**

Police/Fire/City Administrator/Economic Development Coordinator/Urban Renewal District

**CONSENT AGENDA**

1. Call to Order/Roll Call
2. Approval of Bills and Payroll
3. Treasurer's Report
4. Approval of March 17, 2015 Council Meeting Minutes, March 27, 2015 Special Council Meeting Minutes, and April 7, 2015 Council Meeting Minutes

**OLD BUSINESS**

**NEW BUSINESS**

5. City – Authorize Mayor to Sign Employment Agreement with William Herrington (attachment)
6. City – Adopt Hiring Policy Amendment Adding Clause for Seasonal Hires (attachment)
7. City – Approve Special Event Permit for Boundary Community Hospital for the Fun Run on May 9, 2015 (attachment)
8. City – Approve Special Event Permit for Selkirk Saddle Club for the Bull Bash on June 12, 2015 (attachment)
9. Water/Sewer – Discuss Capitalization Fees and Set Hearing Date (attachment)

10. Water – Discuss Cassia Water Tank Project (attachment)
11. Street – Discuss Fairgrounds Storm Sewer (attachment)
12. Police – Authorization to Advertise for Hiring an Officer (attachment)
13. Pool – Hire Head Lifeguard (attachment)
14. Electric – Hire Electric Department General Maintenance and Operations Technician
15. City – Reading of Ordinance Amending Bonners Ferry City Code Title 5, Chapter 5 Pertaining to Use of Firearms within the City Limits (attachment)
16. City – Consider Adoption of Ordinance Amending Bonners Ferry City Code Title 5, Chapter 5 Pertaining to the Use of Firearms within the City Limits
17. City – Authorize Mayor to Sign Memorandum of Agreement between Federal Highway Administration, Idaho Transportation Department, and Idaho State Historic Preservation Officer Regarding the Round Prairie Creek Bridge (ITD Bridge No. 18790), Boundary County (attachment)
18. Fire – Discuss Possibly Contracting for Fire Protection at the Kootenai Wildlife Refuge
19. City – Accept Councilman Tom Mayo's Resignation Effective June 30, 2015 (attachment)

**EXECUTIVE SESSION PURSUANT TO IDAHO CODE 67-2345, SUBSECTION 1**

(a) Consider hiring a public officer, employee, staff member or individual agent.
(b) Consider the evaluation, dismissal or disciplining of, or to hear complaints or charges brought against, a public officer, employee, staff member or individual agent, or public school student.
(c) Conduct deliberations concerning labor negotiations or to acquire an interest in real property which is not owned by a public agency.
(d) Consider records that are exempt from disclosure as provided in chapter 3, title 9, Idaho Code.
(e) Consider preliminary negotiations involving matters of trade or commerce in which the governing body is in competition with governing bodies in other states or nations.
(f) Communicate with legal counsel for the public agency to discuss the legal ramifications of and legal options for pending litigation, or controversies not yet being litigated but imminently likely to be litigated.
(g) Engage in communications with a representative of the public agency's risk manager or insurance provider to discuss the adjustment of a pending claim or prevention of a claim imminently likely to be filed.

**ADJOURNMENT**

**NEXT MEETING DATE**

**INFORMATION**

20. City – 2015 AIC Spring District Meeting in Coeur d'Alene on April 23, 2015
21. City – PRIMA Training on May 12, 2015 in Coeur d'Alene
22. City – AIC Conference in Boise June, 2015
23. Sewer – Claim for Damage (attachment)
24. Electric – Power Issues Presentation (attachment)

# EMPLOYMENT AGREEMENT

THIS AGREEMENT is entered into to be effective the 1st day of May, 2015, by and between the CITY OF BONNERS FERRY, (CITY), a municipal corporation of the State of Idaho and HERRINGTON & ASSOCIATES, PLLC, - WILLIAM L. HERRINGTON, with its purpose being to engage the legal services of WILLIAM L. HERRINGTON (ATTORNEY) as Attorney for the CITY during periods that the City Attorney is not available.

WITNESSETH:

WHEREAS, the Mayor and City Council of the City of Bonners Ferry recognize the CITY'S ongoing need for legal services from counsel with experience in the field of municipal law; and,

WHEREAS, the ATTORNEY has substantial local government law, city planning, and urban renewal experience and the skills and resources to respond to the CITY's needs;

**NOW, THEREFORE, in consideration of the mutual promises contained herein, the CITY and the ATTORNEY agree as follows:**

**1.0 <u>ATTORNEY SERVICES</u>**. The ATTORNEY hereby agrees to provide the following services to the CITY:

**1.1 CITY MEETIGS.** ATTORNEY shall attend CITY meetings when requested unless impossible due to circumstances beyond the control of the ATTORNEY.

**1.2 PLANNING AND ZONING MEETINGS.** ATTORNEY will attend Planning and Zoning meetings if requested unless unable to attend due to circumstances beyond the control of the ATTORNEY.

**1.3 ADVISING STAFF.** ATTORNEY will be available by telephone and in person to promptly advise the CITY members and staff regarding all urban renewal legal issues.

**1.4 REVIEW AND PREPARATION OF DOCUMENTS.** The ATTORNEY shall review all documents of a potentially legal nature and shall prepare such documents as requested. Documents contemplated for review or preparation shall include, but not be limited to, all contracts, agreements, bid specifications, resolutions, ordinances, and ordinance summaries, as requested by the CITY. Additionally, ATTORNEY shall review agendas for upcoming CITY meetings prior to such meetings.

**1.5 OTHER SERVICES.** The ATTORNEY will provide municipal prosecution services as requested, and, at the request of the CITY, will draft legislation and produce written reports and legal opinions, will make presentations to CITY officials and staff and will be available to travel as necessary to perform the obligations of this agreement. The ATTORNEY shall provide a monthly report accounting for hours spent on each project.

**1.6 LITIGATION.** The ATTORNEY shall represent the CITY in civil and criminal litigation upon the specific request of the CITY. ATTORNEY reserves the right to decline such representation where he believes special skills are required or when circumstances beyond his control warrant such action.

**1.7 QUALITY OF SERVICES.** The ATTORNEY shall make his best effort to provide the highest quality legal services necessary to meet the CITY'S needs at the lowest possible expense. ATTORNEY will perform duties assumed under this agreement in accord with standards of professional conduct in the legal profession. In accordance with such standards, time is of the essence in performance with the terms of this agreement.

**2.0 NOT EXCLUSIVE.** The agreement shall not be deemed exclusive; the CITY may hire outside legal counsel when specific legal expertise is needed and ATTORNEY is free to represent other municipal clients.

**3.0 TERMS AND PAYMENT FOR SERVICES.** ATTORNEY shall not be an employee of the CITY. For all services rendered by Attorney under this Agreement, Attorney shall be entitled to the following compensation and benefits:

**3.1 COMPENSATION.** The ATTORNEY shall be compensated in accordance with the attached Fee Schedule.

**3.2 BENEFITS.** ATTORNEY is not entitled to any benefits offered other CITY Attorneys

**3.3 WITHHOLDING.** The CITY shall not be responsible to withhold from ATTORNEY'S wages the required Attorney PERSI contribution and any required state or federal employment taxes.

**3.4 PARALEGAL/SECRETARY.** The ATTORNEY shall provide his own paralegal and secretarial support, but will use CITY staff if available and authorized by the City Clerk.

**3.5 PAYMENT.** The CITY will pay the ATTORNEY monthly in accordance with the attached fee schedule. The ATTORNEY will send a memorandum monthly, which will accurately reflect the hours spent on CITY projects and other expenses.

**3.6 MISCELLANEOUS EXPENSES.** The CITY hereby agrees to reimburse the ATTORNEY for the following other expenses at the rates incorporated in the attached fee schedule.

**3.6.a** For travel expenses or special workshops approved in advance by the CITY.

**3.6.b** The CITY will be charged a minimum of 2.0 hours for CITY meetings or hearings attended by the ATTORNEY (travel time and mileage will be not be charged).

3.6.c For copy and fax expenses.

3.7.d For such other expenses as the parties deem appropriate as agreed to in advance of incurring such expenses.

4.0 **DOCUMENTS**. All documents and notes in the ATTORNEY'S files shall remain the property of the ATTORNEY. However, the CITY shall have the right to view and obtain copies of all documents and paperwork prepared at CITY'S expense.

5.0 **TERM OF EMPLOYMENT**. There is no specific term for this employment. ATTORNEY, as an appointed officer of the CITY, is an "at will" Attorney of the CITY and is subject to termination pursuant to Idaho Code Title 50, Chapter 2. In the event of termination of the Agreement by either party with 30 days notice, the ATTORNEY shall be entitled to be compensated for the hours that he has worked, but shall not be entitled to any lump sum severance package.

6.0 **COMMUNICATIONS**. The CITY shall forward to the ATTORNEY copies of all City Council and Planning/Zoning Commission agendas and minutes and shall keep the ATTORNEY informed of all claims and other matters which may require legal evaluation.

7.0 **PUBLIC OFFICIAL**. ATTORNEY shall be a public official functioning as the acting City Attorney under this contract.

8.0 **GOVERNING LAW**. This agreement shall be governed and interpreted in accordance with the laws of the State of Idaho. Jurisdiction for resolution of disputes arising from performance of this agreement shall rest with the courts of the State of Idaho with venue lying in Bonner County. Should legal action be necessary to enforce the terms of this agreement, the prevailing party shall be entitled to its reasonable costs and attorney's fees.

9.0 **DISPUTE RESOLUTION**. The ATTORNEY agrees that he will not bring suit against the CITY concerning events arising out of the performance of this agreement except for non-payment of compensation or for intentional wrongful conduct which harms the ATTORNEY. The CITY'S right to recover against the ATTORNEY shall be limited to causes of action related to intentional conduct adverse to the CITY'S interest, or to ATTORNEY'S failure to perform duties assumed under this agreement.

10.0 **THIRD PARTY CLAIMS**. To the extent of other third party claims or causes of action, the CITY agrees to hold the ATTORNEY harmless and the ATTORNEY agrees to cooperate fully in the mutual defense of such claims or causes of action. The ATTORNEY shall be added to any insurance currently providing errors and omissions insurance for CITY officials or Attorneys. The CITY will provide a defense for ATTORNEY to any third party action in the same manner and to the same extent as provided for Attorneys pursuant to Idaho Code Section 6-903 with a subsequent right of recovery against ATTORNEY limited by the provisions of this agreement.

**11.0** **ADDRESSES**. Addresses of the parties for all purposes under this agreement shall be as follows:

City of Bonners Ferry
C/O City of Bonners Ferry
PO Box 149
Bonners Ferry, ID 83805

WILLIAM L. HERRINGTON
1732 Lakeshore Dr.
Sagle, ID 83860

Either party may, from time to time, change their address by giving the other party written notice.

**12.0** **NONWAIVER; SEVERABILITY; ENTIRE AGREEMENT**.

**12.1** Failure of either party to exercise any of the rights under this Agreement, or breach thereof, shall not be deemed to be a waiver of such right or a waiver of any subsequent breach.

**12.2** In the event that any provision of this agreement shall be held unenforceable or invalid by a court of competent jurisdiction, the provisions not affected by said decision shall remain in full force and effect.

**12.3** This document constitutes the entire Agreement between the parties and can only be modified or amended in writing by the parties.

**IN WITNESS WHEREOF**, the CITY, by and through its officers, and the ATTORNEY have set their respective hands on this agreement the day and year first set forth above.

CITY of BONNERS FERRY

____________________________
Mayor

(seal)

Attest:

____________________________
City Clerk

ATTORNEY:

____________________________
William L. Herrington

## FEE SCHEDULE (hourly rates)

Municipalities Under Ongoing Contract:

| | | |
|---|---|---|
| General Matters<br>Under Contract | | $140.00 |
| Administrative Hearings | | $200.00 |
| Litigation | | $250.00 |
| Legal Intern (when applicable) | | $60.00 |
| Secretary (when applicable) | | $50.00 |
| Copies | $ .30 per | |
| FAX | .50 per | (+ long distance) |
| Mileage | .55 per | |

***Late Charge***: Any account past due for 30 days will be charged an additional one and one half percent (1.5%) service charge on the unpaid balance

POLICY III.H HIRING POLICY

A. GENERAL

It is the goal of the City of Bonners Ferry to hire and/or promote individuals whose skills, abilities, and attitudes best enhance the City's ability to provide the best possible level of cost effective service to its citizens. This policy is not applicable to Mayoral appointments and volunteers.

B. ADVERTISING

1. All open positions will be advertised at the State of Idaho Job Service.
2. Job postings are to reference the City's equal employment opportunity and non-discrimination policies
3. Positions may also be advertised in the local newspaper, industry trade journals and web sites when appropriate to increase the pool of qualified applicants.
4. The time the position is open for submission of applications is based on the time expected to obtain a list of qualified applicants. If after the position is closed and there is a desire to obtain additional applicants the position will be readvertised.
5. Candidates will be required to turn in the standard application form and a copy of their valid driver's license to the job service and may be required to include resumes, letters of references, and/or certifications.
6. Exceptions:
   - a) For positions to be filled with in-house candidates the opening will be noticed to all potentially qualified employees. The notice will include the position and closing dates. Also refer to the personnel policy 3A.IV.E.
   - ~~6.~~b) Seasonal positions may be filled with the employee(s) from previous years without a competative hiring process upon recommendation from the department head.

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C. INTERVIEWING

1. A list of individuals for interview will be made from review of the applications. This review will include contacting references and where possible additional people who know the applicant.
2. When possible the City will interview a slate of two to four applicants.
3. The interview team will consist of the same three or four individuals for all candidates with at least one interview team member being a City employee from outside the department with the open position.

D. PRE-EMPLOYMENT CHECKS
(APPLICABLE TO HIRES WHO ARE NOT CURRENT EMPLOYEES)

1. Further contact of references and existing and prior employers will be made if the person is not well known.
2. All potential employees will have a pre-employment physical and drug test.
3. The City will conduct a criminal background check on applicants.

E. RECOMMENDATION AND CONFIRMATION

1. From the interviewed candidates the supervisor will recommend to the Mayor and Council the person to be hired.

F. PROBATIONARY EMPLOYEES

It is the policy of the City of Bonners Ferry that any employee who applies for a promotion of any kind within the department in which they are currently employed, must be in good standing and not on probationary status. Probationary status may be the result of the employee being a newly hired employee, for disciplinary actions, or any other documented reason.

RECEIVED

APR 03 2015

CITY OF BONNERS FERRY

**CITY OF BONNERS FERRY, IDAHO**

APPLICATION FOR CITY SPECIAL EVENT PERMIT

(REQUIRED UNDER ORDINANCE NO. 468)

Date of Application 3/25/15

License Issued to: Boundary Community Hospital

Business Name: " "

Mailing Address: 6640 Kaniksu Street

Physical Address: " "

Phone Number: 208.267.6912

Type of Event: Fun Run

Dates of Event: May 9, 2015

Location of Event: Boundary Community Hospital

Time of Event: Registration 7am ; Races 8 am

By application, the applicant shall, waive, indemnify, and hold harmless the City of Bonners Ferry, its agents, its employees and authorized volunteers from and against all claims, damages, losses and expenses, including attorneys' fees, arising out of the permitted activity or the conduct of applicant's operation of the event if such claim (1) is attributed to personal injury, bodily injury, disease or death, or to injury or to destruction of property, including the loss of use there from, and (2) is not caused by any gross negligent act or omission or willful misconduct of the City of Bonners Ferry or its employees acting within the scope of their employment.

The following requirements must be met:

A. If sponsored by a local resident, entity or group, a signed copy of licensee's contract with the local sponsor.
B. Evidence of at least one million dollars ($1,000,000.00) combined single limit liability insurance that names the City as co-insured.
C. A clean-up fee of one hundred dollars ($100.00); all, some or none of which will be returned upon recommendation of the Chief of Police after his inspection of the premises after the organization has left the premises and their permit expired. The foregoing fee is subject to change from time to time by resolution of Council.

**Fees and proof of insurance must be provided to the City of Bonners Ferry prior to the event.**

Authorized Signature for Applicant [signature]

Printed Name Rachel Figgins

Office/Title Marketing Assistant

**Office Use:**

Fee Paid 135.00 Date 4/3/15 Receipt No.________

Approved By________ Date________

2015-4

CITY OF BONNERS FERRY, IDAHO
APPLICATION FOR CITY SPECIAL EVENT PERMIT
(REQUIRED UNDER ORDINANCE NO. 468)

Date of Application 4-1-15
License Issued to: Christine McNair / Selkirk Saddle club
Business Name: Selkirk Saddle Club
Mailing Address: PO Box 1958
Physical Address:
Phone Number: 267-3105
Type of Event: Bull Bash
Dates of Event: June 12, 2015
Location of Event: Boundary County Fairgrounds
Time of Event: 7pm

RECEIVED
APR 01 2015
CITY OF BONNERS FERRY

By application, the applicant shall, waive, indemnify, and hold harmless the City of Bonners Ferry, its agents, its employees and authorized volunteers from and against all claims, damages, losses and expenses, including attorneys' fees, arising out of the permitted activity or the conduct of applicant's operation of the event if such claim (1) is attributed to personal injury, bodily injury, disease or death, or to injury or to destruction of property, including the loss of use there from, and (2) is not caused by any gross negligent act or omission or willful misconduct of the City of Bonners Ferry or its employees acting within the scope of their employment.

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A. If sponsored by a local resident, entity or group, a signed copy of licensee's contract with the local sponsor.
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C. A clean-up fee of one hundred dollars ($100.00); all, some or none of which will be returned upon recommendation of the Chief of Police after his inspection of the premises after the organization has left the premises and their permit expired. The foregoing fee is subject to change from time to time by resolution of Council.

**Fees and proof of insurance must be provided to the City of Bonners Ferry prior to the event.**

Authorized Signature for Applicant Christine McNair

Printed Name Christine McNair

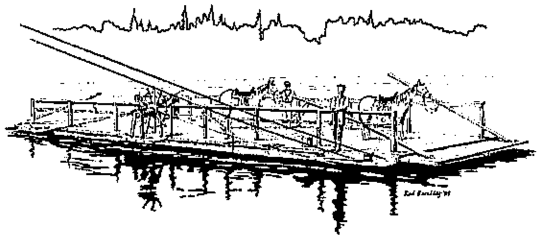
Office/Title Treasurer / Secretary

Office Use:

Fee Paid ~~ck~~ $135 Date 4-1-15 Receipt No. 11814-2

Approved By Date

2015-3



# MEMO

CITY OF BONNERS FERRY
CITY ADMINISTRATOR

Date: 9 April 2015
To: City Council
From: Stephen Boorman, City Administrator
Subject: Water and Sewer Capitalization Fees.

When we did the water and sewer rate increases we did not include an increase to the Capitalization Fees. Attached are current recommended capitalization fees based on the original cost method and the replacement cost method.

It would be our recommendation that the Council consider implementing the identified Cap fees based on a replacement cost method for both water and sewer.

SJB

## Water Capitalization Fees

April 13, 2015

### ORIGINAL COST METHOD

| | | |
|---|---|---|
| Gross Plant (9/30/13) | 13,249,664 | Excludes grant funded capital and customer contributions. |
| Net Plant (9/30/13) | $8,360,872 | |
| Depreciated Plant | 36.9% | |
| Outstanding Principal (9/30/13) | | |
| STD | $406,127 | |
| LTD | $2,798,149 | |
| | $3,204,276 | |
| Capitalized Net Plant | $5,156,596 | |
| **Capitalized Net Plant/eq. meter** | **$2,591** | /equivalent meter |

### REPLACEMENT COST METHOD

| | | |
|---|---|---|
| Replacement Cost Revised | $40,827,610 | Welch Comer 1/29/15 |
| Less Grant/Customer Cont. | $22,137,168 | 54.2% of gross plant |
| Gross Plant | $18,690,442 | |
| Less Depreciation | $9,762,096 | 52.2% of Gross Plant per Welch Comer |
| Net Plant | $8,928,346 | |
| Less Outstanding Debt (1/5/15) | $2,862,801 | |
| Capitalized Net Plant | $6,065,545 | |
| **Capitalized Net Plant per Eq. Meter** | **$3,047.60** | /equivalent meter |

## Water Capitalization Fees

April 13, 2015

### ADDITIONAL DATA

| Meter Size | Meters | Weighting Factor | Equivalent Meters |
|---|---|---|---|
| 3/4 x 5/8 | 1,235 | 1.0 | 1,235 |
| 1 | 47 | 2.5 | 117 |
| 1 1/2 | 23 | 5.0 | 115 |
| 2 | 46 | 8.0 | 364 |
| 3 | 4 | 15.0 | 58 |
| 4 | 4 | 25.0 | 102 |
| Total Meters | 1,358 | | 1,990 |

| | | |
|---|---|---|
| **Depreciation (per Welch Comer estimated value)** | | |
| Estimated Gross Plant (1/29/2015) | 40,827,610 | |
| Net Plant | 19,503,178 | |
| Percent of Plant Depreciated | **52.2%** | |
| | | |
| **Capital** | | |
| Debit | 27,437,242 | |
| Credit | 19,035,357 | |
| | | |
| Added Capital (00-14) | 8,401,885 | |
| Per Year | 560,126 | |
| | | |
| **Customer Contrubutions** | | |
| Pre-2000 | 626,316 | |
| 2000 - 2014 | 57,290 | |
| | | |
| Per year | 3,819 | 0.7% |
| | | |
| **Grants (2004 - 2014)** | **3,298,755** | |
| | | |
| Per year | 299,887 | 53.5% |
| | | |
| **Interfund Loans** | | |
| Debit | 1,280,726 | |
| Credit | 1,476,275 | |
| | | |
| Outstanding | 195,549 | |
| | | |
| **Debt** | | |
| Debit | 3,318,372 | |
| Credit | 6,075,777 | |
| | | |
| Outstanding | 2,757,406 | |
| | | |
| **Water Bond Debt Reserve** | | |
| Debit | 117,962 | |
| Credit | 27,808 | |
| | | |
| Outstanding | (90,154) | |

## Wastewater Capitalization Fees

April 13, 2015

### ORIGINAL COST METHOD

| | | |
|---|---|---|
| Gross Plant (9/30/13) | 1,841,212 | |
| Net Plant (9/30/13) | $470,234 | |
| Depreciated Plant | 74.5% | |
| Outstanding Principal | | |
| LTD (9/30/13) | $29,379 | |
| | $29,379 | |
| Capitalized Net Plant | $440,855 | |
| **Capitalized Net Plant/ERU** | **$217** | /ERU (ERU=4500 gal) |

### REPLACEMENT COST METHOD

| | | |
|---|---|---|
| Replacement Cost | $12,300,000 | "BF public meeting June 26 2013.pdf" |
| Less Grant/Customer Cont. | $2,764,076 | 22.5% of gross plant |
| Gross Plant | $9,535,924 | |
| Less Depreciation | $7,100,508 | 74.5% of Gross Plant |
| Net Plant | $2,435,416 | |
| Less Outstanding Debt (1/5/15) | $0 | |
| Capitalized Net Plant | $2,435,416 | |
| **Capitalized Net Plant per ERU** | **$1,196** | per ERU (ERU=4500gal) |

## Wastewater Capitalization Fees

April 13, 2015

### ADDITIONAL DATA

| Customer Classes | 4500gal/ERU | 6000gal/ERU |
|---|---|---|
| Residential | 955 | 955 |
| Small Commercial | 729 | 547 |
| Commercial | 347 | 260 |
| Industrial | 3 | 2 |
| Interdepartmental | 1 | 1 |
| Total | 2,036 | 1,766 |

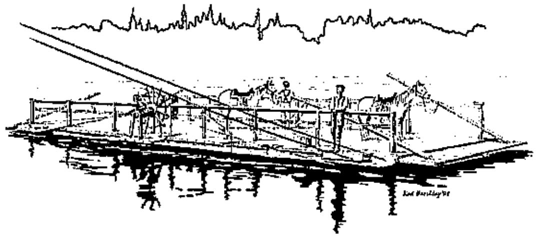
| **Plant Additions** | | |
|---|---|---|
| Debit | $5,313,592 | |
| Credit | $4,820,266 | |
| | | |
| Added Capital (00-14) | $493,327 | |
| **Per Year** | **$32,888** | |

| **Customer Contrubutions** | | |
|---|---|---|
| Pre-2000 | $123,317 | |
| 2000 - 2014 | $2,054 | |
| **Per year** | **$137** | **0.4%** |
| | | |
| **Grants (2000 - 2014)** | $108,807 | |
| **Per year** | **$7,253.80** | 22.1% |

| **Interfund Loans** | |
|---|---|
| Debit | $188,357 |
| Credit | $188,357 |
| **Outstanding** | **$0** |

| **Debt** | |
|---|---|
| Debit | $0 |
| Credit | $0 |
| **Outstanding** | **$0** |

| **Sewer Bond Debt Reserve** | |
|---|---|
| Debit | $0 |
| Credit | $0 |
| **Outstanding** | **$0** |



# MEMO

CITY OF BONNERS FERRY
CITY ADMINISTRATOR

Date: 17 April 2015
To: City Council
From: Stephen Boorman, City Administrator
Subject: Cassia northside tank replacement.

As we have previously discussed, the soils engineers have identified issues with the slope steepness and soil type for the replacement of the Cassia Tank. Attached are two estimates, one is the estimated cost to construct the tank at a different location and the second is to provide structural reinforcement so that the current location could be used. The expense of the two options is estimated to be very close. The big downside of relocation would be the impacts to the grant application that we hope to have approved in the near future.

Therefore, it is our recommendation to proceed with this project at the current location.

Thanks

SJB

## City of Bonners Ferry

## North Tank Replacement (350,000 gallons) - Site 1 and Waterline Replacement

## ENGINEER'S OPINION OF PROBABLE CONSTRUCTION COST

**Cast In Place**

| | | | | | |
|---|---|---|---|---|---|
| Prepared By: | Necia Maiani, PE and Steve Cordes, PE | Date: | 7-Apr-15 | | |
| PM Approval: | | Date: | | | |
| **Pay Item** | **Description** | **Pay Unit** | **Estimated Quantity** | **Unit Price** | **Total** |
| **CONSTRUCTION** | | | | | |
| | Mobilization | LS | 1 | $28,800.00 | $28,800.00 |
| | Geotech Stabilzation | LS | 1 | $90,000.00 | $90,000.00 |
| | Site Control | LS | 1 | $11,000.00 | $11,000.00 |
| | Clearing and Grubbing | LS | 1 | $10,000.00 | $10,000.00 |
| | Site Grading and Excavation | LS | 1 | $25,000.00 | $25,000.00 |
| | Demolish Roof Structure | LS | 1 | $5,000.00 | $5,000.00 |
| | Cast in Place Concrete Reservoir | GAL | 350,000 | $1.38 | $483,000.00 |
| | Replace Steel Piping, Including Inlet/Outlet Extension | LF | 420 | $100.00 | $42,000.00 |
| | Valves | EA | 6 | $2,200.00 | $13,200.00 |
| | | | | Total: | $708,000.00 |
| | | | | Construction Contingency (10%) | $70,800.00 |
| | | | | | **$778,800.00** |
| **ENGINEERING** | | | | | |
| | Right of Way | LS | 1 | $3,500.00 | $3,500.00 |
| | Geotechnical | LS | 1 | $10,250.00 | $10,250.00 |
| | Design Phase | LS | 1 | $71,400.00 | $71,400.00 |
| | Civil | LS | 1 | $36,900.00 | $36,900.00 |
| | Structural | LS | 1 | $34,500.00 | $34,500.00 |
| | Bid Phase | LS | 1 | $5,500.00 | $5,500.00 |
| | Construction Phase | LS | 1 | $37,250.00 | $37,250.00 |
| | RPR | LS | 1 | $26,000.00 | $26,000.00 |
| | | | | **Total Estimated Project Cost:** | **$932,700.00** |

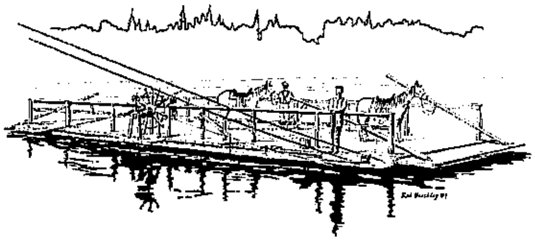
## City of Bonners Ferry

## North Tank Replacement (350,000 gallons) - Site 2 and Waterline

## ENGINEER'S OPINION OF PROBABLE CONSTRUCTION COST

### Cast In Place

| | | | | | |
|---|---|---|---|---|---|
| Prepared By: | Necia Maiani, PE and Steve Cordes, PE | Date: | 7-Apr-15 | | |
| PM Approval: | | Date: | | | |
| **Pay Item** | **Description** | **Pay Unit** | **Estimated Quantity** | **Unit Price** | **Total** |
| **CONSTRUCTION** | | | | | |
| | Mobilization | LS | 1 | $33,000.00 | $33,000.00 |
| | Site Control | LS | 1 | $11,000.00 | $11,000.00 |
| | Clearing and Grubbing | LS | 1 | $10,000.00 | $10,000.00 |
| | Site Grading and Excavation | LS | 1 | $25,000.00 | $25,000.00 |
| | Access Road | LS | 1 | $28,000.00 | $28,000.00 |
| | Cast in Place Concrete Reservoir | GAL | 350,000 | $1.38 | $483,000.00 |
| | Replace Steel Piping, Including Inlet/Outlet Extension | LF | 1,350 | $75.00 | $101,250.00 |
| | Valves | EA | 6 | $2,200.00 | $13,200.00 |
| | | | | Total: | $704,450.00 |
| | | | | Construction Contingency (10%) | $70,500.00 |
| | | | | | **$774,950.00** |
| **ENGINEERING** | | | | | |
| | Right of Way | LS | 1 | $10,000.00 | $10,000.00 |
| | Geotechnical | LS | 1 | $14,000.00 | $14,000.00 |
| | Design Phase | LS | 1 | $74,500.00 | $74,500.00 |
| | Civil | LS | 1 | $40,000.00 | $40,000.00 |
| | Structural | LS | 1 | $34,500.00 | $34,500.00 |
| | Bid Phase | LS | 1 | $5,500.00 | $5,500.00 |
| | Construction Phase | LS | 1 | $37,250.00 | $37,250.00 |
| | RPR | LS | 1 | $26,000.00 | $26,000.00 |
| | | | | Total: | $167,250.00 |
| | | | | **Total Estimated Project Cost:** | **$942,200.00** |



# MEMO

CITY OF BONNERS FERRY
CITY ADMINISTRATOR

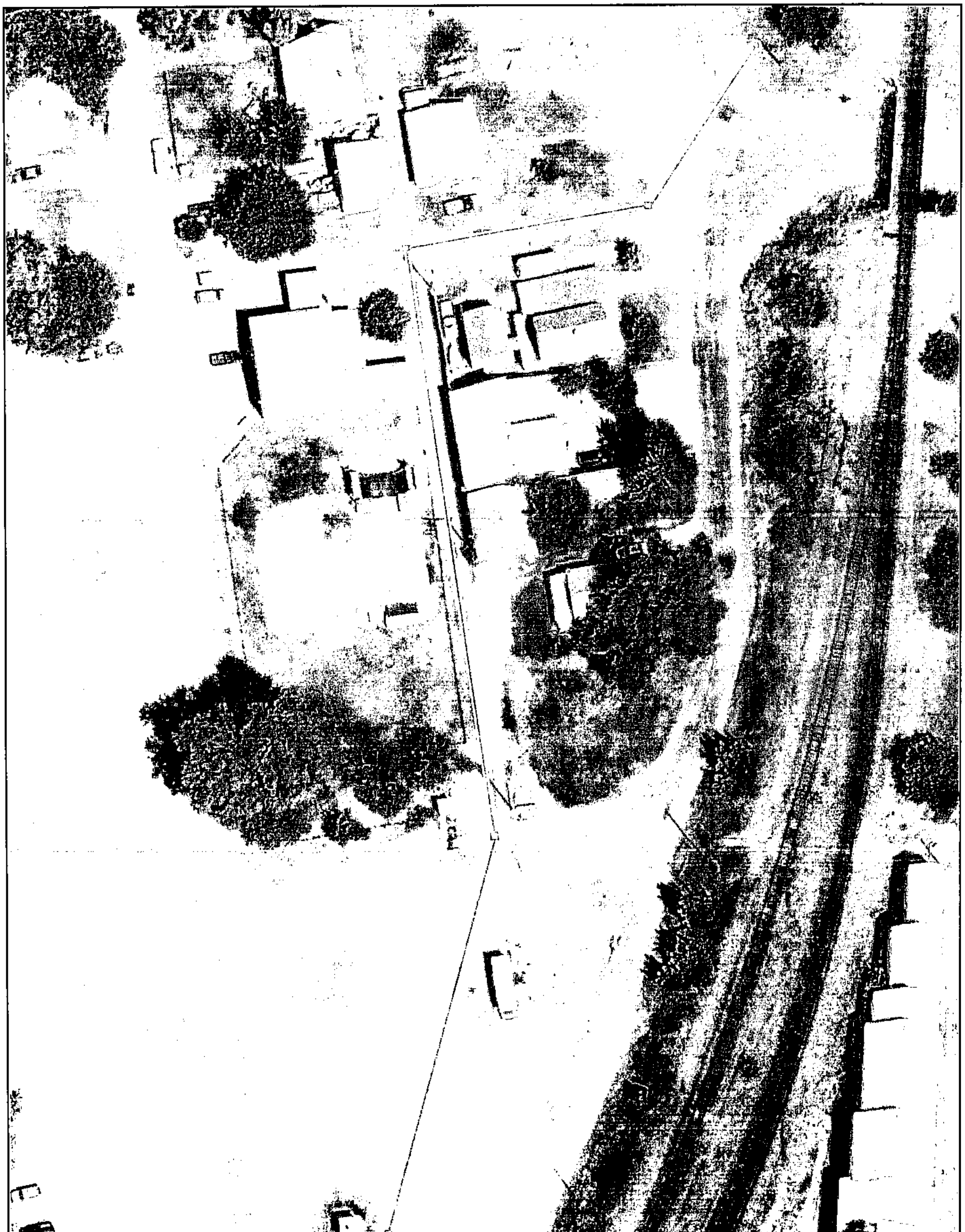
Date: 17 April 2015
To: City Council
From: Stephen Boorman, City Administrator
Subject: Fairgrounds Storm Sewer.

We have been reviewing the possibility of adding a storm sewer line to the fairgrounds area for a number of years. Currently all of the storm water in the fairground area is pumped out using the pump station in the fairground parking lot. Also, when the river hits an elevation of 1763-1765 the downtown storm sewer cannot gravity drain into the river. At that time we close a valve in the stormdrain system and use a portable pump to pump this water into the river.

Attached is drawing of the proposed storm sewer line prepared by Mike Klaus. There are two benefits of this additional line. First, is that the pump station in the fairgrounds parking lot would not be required under normal conditions. Second, during high water events the pump station could be used to pump storm water out of the downtown and fairgrounds area.

At this time we are proceeding towards have a bid-ready design and then looking for opportunities for a grant and/or working with the county to construct this line. John Youngwirth has priced the material and the material cost for this project would be around $6,000. We are not requesting specific council action at this time but would like you to be aware of this project

SJB



City of Bonners Ferry Police Lieutenant

The City of Bonners Ferry, located on the banks of the Kootenai River, population 2,500 is the county seat for Boundary County with a total county population of around 11,000. Our community has its own hospital and an excellent public school system. Boundary County is a wonderful location for outdoor recreation including hiking, hunting, fishing, and skiing.

The Police department currently consists of 7 full time Officers (including the Chief) and provides 24/7 law enforcement service to the City. The Police Department includes a DARE/SRO position that serves all of the schools located within Boundary County. The Police Department also has an active Reserve Program. All of the Dispatching is done by the Boundary County Sheriff's Office, with which the City has a good working relationship.

Required Qualification:

- A valid Idaho class D driver's license
- Idaho P.O.S.T. certification or ability to obtain Idaho P.O.S.T. certification by Reciprocity
- Three (3) years minimum experience in sworn law enforcement with supervisory experience desirable.
- If a current City of Bonners Ferry employee, you must not be on probation either as a newly hired officer or for any disciplinary reasons.

Desirable Background:

- Advanced P.O.S.T. certifications such as advanced, supervisory, and masters
- An Advanced Law Enforcement Certificate or completion of upper management training, such as the FBI National Academy or FBI Command College
- Advanced education such as an Associate's degree or B.A. from an accredited college or university, course work in criminology, law enforcement, social science or public administration a plus
- Training in employment law, labor issues, and personnel management.

Job Duties:

The position of Police Lieutenant serves as a patrol supervisor and watch commander. The position is responsible for the oversight of patrol and investigative duties within the police department. This position assists the chief of police in planning, organization and administration of the City's comprehensive police services and law enforcement program; provides expert professional assistance to City management staff in areas of expertise; fosters cooperative working relationships with other city departments, citizen groups, and other law enforcement agencies on police matters; performs related work as assigned. Helps develop and direct the implementation of schedules, goals, objectives, policies, procedures and work standards for the department. Directs and oversees criminal and patrol investigations in the city limits.

Desired Personal Characteristics:

- Leadership, Integrity, Role Model, and ability to communicate openly and honestly
- Ability to works well with the Mayor, City Council, City Citizens, other law enforcement agencies, other governmental agencies, subordinates, and other City Departments.

Compensation:

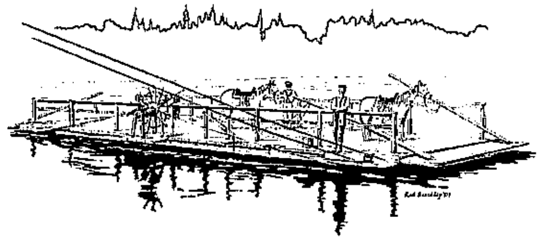
Pays $45,000-$47,249 (Depending on qualifications) Annually plus benefits.

EEO and Veterans Preference:

The City of Bonners Ferry is an Equal Employment Opportunity employer and will accord a preference to employment of veterans of the U.S. Armed Services in accord with provisions of Idaho Code § 65-502. If the applicant is claiming preference it must be so stated in the cover letter and documentation of military service and honorable discharge must be provided with application.

Specific questions about the position may be directed to Chief Victor Watson at 208-267-4391 or vwatson@bonnersferry.id.gov

Only qualified applicants apply with resume and cover letter. Dept. of Labor/Bonners Ferry will hold resume`s for employer until closing date of 12:00 p.m. May 15, 2015. The Bonners Ferry office must receive resumes by 12:00 pm on the closing date or they will not be considered



# MEMO

CITY OF BONNERS FERRY
CITY ADMINISTRATOR

---

Date: 3 April 2015
To: City Council
From: Stephen Boorman, City Administrator
Subject: Head Lifeguard Hire.

We would recommend that the City hire Olivia Langs as the Head Lifeguard for our pool.

Thanks

SJB

ORDINANCE NO. ______

AN ORDINANCE OF THE CITY OF BONNERS FERRY, A MUNICIPAL CORPORATION OF THE STATE OF IDAHO, AMENDING BONNERS FERRY CITY CODE TITLE FIVE, CHAPTER FIVE CONCERNING FIREARMS; REPEALING SECTION 5-5-2 CONCERNING CONCEALED WEAPONS; RENUMBERING SECTION 5-5-3; RENUMBERING SECTION 5-5-4 AND PROVIDING FOR EXCEPTIONS; ENACTING A NEW SECTION 5-5-4 PERTAINING TO VIOLATIONS; PROVIDING SEVERABILITY; PROVIDING THAT THIS ORDINANCE SHALL BE IN FULL FORCE AND EFFECT FROM AND AFTER ITS PASSAGE, APPROVAL AND PUBLICATION ACCORDING TO LAW.

WHEREAS, the Mayor and City Council find it in the interest of the citizens of Bonners Ferry to enact amendments within Bonners Ferry City Code Title Five Chapter Five pertaining to the use of firearms within the city limits in order to ensure public safety.

NOW THEREFORE, Be it ordained by the Mayor and the Council of the City of Bonners Ferry, Idaho, as follows:

**Section 1: That Bonners Ferry City Code Section 5-5-2 is hereby repealed.**

**Section 2: That Bonners Ferry City Code Section 5-5-3 is hereby amended as follows:**

5-5-2 ~~5-5-3~~: DISCHARGE PROHIBITED:

It shall be unlawful for any person to discharge firearms of any kind or description within the limits of the city.~~; provided, however, that this shall not apply to police officers in the discharge of their duties.~~

**Section 3: That Bonners Ferry City Code Section 5-5-4 is hereby amended as follows:**

5-5-3 ~~5-5-4~~: EXCEPTIONS~~; PERMIT REQUIRED~~:

A. Shooting Galleries, Gun Clubs, Etc.; Permit Required: The city council may, upon application, grant permits to shooting galleries, gun clubs and others for shooting within the city limits in fixed localities and under fixed rules. Such permits shall be in writing attested by the clerk conforming to such requirements as the council shall demand, and the permit thus issued shall be subject to revocation at any time by action of the council.

B. Law Enforcement: This chapter does not apply to those persons listed in section 18-3302(12)(a through c), Idaho Code, while acting in their official capacity.

C. A person discharging a firearm in the lawful defense of person or persons or property.

**Section 4: That a new section 5-5-4 of Bonners Ferry City Code is hereby adopted:**

5-5-4: VIOLATIONS:

Any person found guilty of a violation of this section may be charged as a misdemeanor with penalties pursuant to Idaho Code.

**Section 5: PROVISIONS SEVERABLE:** The provisions of this Ordinance are hereby declared to be severable and if any provision of this Ordinance or application of such provision to any person or circumstance is declared invalid for any reason, such declaration shall not affect the validity of remaining portions of this Ordinance.

**Section 6: EFFECTIVE DATE**: This ordinance shall be effective upon its passage and publication in the manner provided by law.

APPROVED by the Mayor and City Council of the City of Bonners Ferry this ______ day of ________________, 2015.

CITY OF BONNERS FERRY, IDAHO

BY: ____________________________________
Mayor

Attest:

____________________________________
Clerk, City of Bonners Ferry

MEMORANDUM OF AGREEMENT
BETWEEN THE FEDERAL HIGHWAY ADMINISTRATION,
IDAHO TRANSPORTATION DEPARTMENT, AND
THE IDAHO STATE HISTORIC PRESERVATION OFFICER
REGARDING THE ROUND PRAIRIE CREEK BRIDGE (ITD Bridge No. 18790),
BOUNDARY COUNTY, IDAHO

WHEREAS, the Federal Highway Administration (FHWA) has determined that the Round Prairie Creek Bridge project, which is described in Attachment A to this Memorandum of Agreement (MOA), in Boundary County, Idaho, will have an adverse effect on the Round Prairie Creek Bridge, a property determined to be eligible for inclusion in the National Register of Historic Places (NRHP); and

WHEREAS, the FHWA has consulted with the Idaho State Historic Preservation Officer (SHPO) pursuant to 36 CFR Part 800 regulations implementing Section 106 of the National Historic Preservation Act (54 U.S.C. § 306108), and notified the Advisory Council on Historic Preservation (ACHP) of the adverse effect finding with specified documentation and the ACHP has chosen not to participate in the consultation pursuant to 36 CFR § 800.6(a)(1)(iii); and

WHEREAS, the FHWA, in consultation with the SHPO, has determined that the undertaking's adverse effects cannot be avoided, and that implementation of the treatments set forth in Stipulation II of this MOA will satisfactorily take into account the undertaking's adverse effects on the historic property; and

WHEREAS, the Idaho Transportation Department (ITD) has agreed to be a signatory in the MOA; and

WHEREAS, the Selkirk International Loop, the Boundary County Historical Society and the City of Bonners Ferry have participated in the consultation and have been invited to concur in the MOA;

NOW, THEREFORE, the FHWA and the SHPO agree that the undertaking shall be implemented in accordance with the following stipulations in order to take into account the effects of the undertaking on historic properties, and further agree that these stipulations shall govern the undertaking and all of its parts until this MOA expires or is terminated.

STIPULATIONS

The FHWA shall ensure that the following stipulations are carried out:

I. Definitions

The definitions provided at 36 CFR § 800.16 are applicable throughout this MOA.

II. Treatment of the Historic Property

Prior to removal of the Round Prairie Creek Bridge (ITD Bridge No. 18790) in Boundary County, the ITD will complete documentation to an appropriate level, to be established by the SHPO. Documentation (photos, etc.) shall be submitted to SHPO for approval and acceptance prior to removing the Round Prairie Creek Bridge. Copies of this documentation shall be made available to the SHPO and appropriate local archives designated by the SHPO.

Within five (5) years of filing the signed agreement with the ACHP, ITD will oversee the production and delivery of interpretive signs to the City of Bonners Ferry and ensure installation by the City at the general locations listed below. ITD will produce the interpretive signs based on text and photos provided by the Boundary County Historical Society that describe the historic US-95 Kootenai River Bridge and the Bonners Ferry Historical Generator. The SHPO will review the text for this interpretive signage prior to finalization and production. The signage will be installed at the following two locations:

- The southern remnant of the historic Kootenai River Bridge (adjacent to approximate MP 507.75 on US-95)
- In the vicinity of 7232 Main St. Bonners Ferry, Idaho, near the remnant Fairbanks Morris Generator which supplied power to the City of Bonners Ferry prior to the establishment of the modern-day electrical grid.

III. Administrative Provisions

A. Confidentiality

The parties to this MOA acknowledge that historic properties covered by this MOA are subject to the provisions of Section 304 of the National Historic Preservation Act of 1966 relating to the disclosure of site information and, having so acknowledged, will ensure that all actions and documentation prescribed by this MOA are consistent with Section 304 of the National Historic Preservation Act of 1966.

B. Resolving Objections

Should any signatory or concurring party to this MOA object at any time to any actions proposed or the manner in which the terms of this MOA are implemented, FHWA shall consult with such party to resolve the objection. If FHWA determines that such objection cannot be resolved, FHWA will:

1. Forward all documentation relevant to the dispute, including the FHWA's proposed resolution, to the ACHP. The ACHP shall provide FHWA with its advice on the resolution of the objection within thirty (30) days of receiving adequate documentation. Prior to reaching a final decision on the dispute, FHWA shall prepare a written response that takes into account any timely advice or comments regarding the dispute from the ACHP, signatories and concurring parties, and provide them with a copy of the FHWA's written response. FHWA will then proceed according to its final decision.

2. If the ACHP does not provide its advice regarding the dispute within the thirty (30) day time period, FHWA may make a final decision on the dispute and proceed accordingly. Prior to reaching such a final decision, FHWA shall prepare a written response that takes into account any timely comments regarding the dispute from the signatories and concurring parties to the MOA, and provide them and the ACHP with a copy of such written response.

C. Amendments

If a signatory determines the terms of the MOA cannot be met or that a change is necessary to meet the requirements of the law, that signatory will immediately request that the consulting parties consider an amendment or addendum. Any necessary amendment or addendum will be executed as defined in the 36 CFR 800 regulations. This MOA may be amended when such an amendment is agreed to in writing by all signatories. The amendment will be effective on the date a copy signed by all of the signatories is filed with the ACHP.

D. Termination
If any signatory determines that the terms of this MOA cannot be or are not being carried out, the signatories shall consult to seek amendment of the agreement. If within thirty (30) days (or another time period agreed to by all signatories) an amendment cannot be reached, any signatory may terminate the MOA upon written notification to the other signatories. If the agreement is not amended, any signatory may terminate it. Once the MOA is terminated, and prior to work continuing on the undertaking, FHWA must either (a) execute an MOA pursuant to 36 CFR § 800.6 or (b) request, take into account, and respond to the comments of the ACHP under 36 CFR § 800.7. FHWA shall notify the signatories as to the course of action it will pursue.

E. Effective Period
This MOA shall be effective upon its execution by the last signatory and shall remain in effect, unless terminated, suspended, or amended, for a period of five years.

EXECUTION of this MOA by the FHWA and the SHPO, its transmittal to the ACHP in accordance with 36 CFR §800.6(b)(1)(iv), and subsequent implementation of its terms, shall evidence, pursuant to 36 CFR §800.6(c), that this MOA is an agreement with the ACHP for purposes of Section 110(l) of the National Historic Preservation Act of 1966, and shall further evidence that the FHWA has afforded the ACHP an opportunity to comment on the undertaking and its effects on historic properties, and that the FHWA has taken into account the effects of the undertaking on historic properties.

SIGNATORIES:

FEDERAL HIGHWAY ADMINISTRATION

BY:______________________________ ______________
(Name/Title) (Date)

IDAHO STATE HISTORIC PRESERVATION OFFICER

BY:______________________________ ______________
(Name/Title) (Date)

IDAHO TRANSPORTATION DEPARTMENT

Recommended By:

______________________________ ______________
Damon Allen, District Engineer (Date)

Approved By:

______________________________ ______________
Brian Ness, Director (Date)

CONCURRING PARTIES:

SELKIRK INTERNATIONAL LOOP

BY:______________________________ ______________
(Name/Title) (Date)

BOUNDARY COUNTY HISTORICAL SOCIETY

BY:______________________________ ______________
(Name/Title) (Date)

CITY OF BONNERS FERRY

BY:______________________________ ______________
(Name/Title) (Date)

MEMORANDUM OF AGREEMENT
BETWEEN THE FEDERAL HIGHWAY ADMINISTRATION,
IDAHO TRANSPORTATION DEPARTMENT, AND
THE IDAHO STATE HISTORIC PRESERVATION OFFICER
REGARDING THE ROUND PRAIRIE CREEK BRIDGE (ITD Bridge No. 18790),
BOUNDARY COUNTY, IDAHO

## Attachment A

**A description of the undertaking, specifying the Federal involvement:**

ITD District 1 is proposing to replace the Round Prairie Creek Bridge on US-95 at MP 532.32. The existing Round Prairie Creek Bridge is a cast in place stiff leg concrete structure that is 24 feet wide (curb to curb) and 31.6 feet long. The bridge will be replaced with a full span concrete beam structure with a span length of 52 feet and an out to out width of 44 feet. The abutments will consist of precast concrete components founded on pilings.

The project also involves a mill and overlay of US-95 between MP 526.67 and 536.560. The work will consist of .32 feet of milling and .32 feet of overlay of the travel lanes and approaches with asphalt plant mix placed in two lifts. Any areas requiring reconstruction, such as bridge approaches, will be paved with .5 feet of plant mix placed with three lifts. In addition to the Round Prairie Creek Bridge, there are three (3) box culverts and one (1) pipe culvert located within the project area.

April 15, 2015

Dave Anderson
Mayor
City of Bonners Ferry
7232 Main St.
Bonners Ferry, ID 83805

Honorable Mayor Anderson,

I am writing to formally notify you that I am resigning my position as City Councilman with the City of Bonners Ferry. My last day will be June 30, 2015.

It has been my honor to serve the City and I feel privileged by my associations with City employees and staff. My time here will always be cherished.

Yours sincerely,

Tom Mayo

Tom Mayo

RECEIVED

APR 09 2015

CITY OF BONNERS FERRY

# NOTICE OF TORT FOR DAMAGES

NAME: GENE OVERMAN
ADDRESS: 6601 CHIPPEWA DR BONNERS FERRY, ID. 83805
LENGTH OF RESIDENCE: 5 YEARS

CELL 208-304-0405

DATE OF INCIDENT: 2/27/15 THROUGH 4/7/15
LOCATION: 6601 CHIPPEWA DR AND CARIBOU ST. BONNERS FERRY ID.

DAMAGE TYPE: SEWER LINE DAMAGE

DESCRIPTION OF EVENT: On approximately Feb 27, 2015 I began to have sewer water backing up in our residence. I contacted the City of Bonners Ferry and their sewer personnel did a cursory inspection and advised me they did not observe any problems in their main line. After attempting to clear drains in my home with no success, I contacted KG&T plumbing for assistance. KG&T ran a camera and a hydro power cleaner down the line. He located multiple locations where there were visible drops in the line near the junction in the street. He also located roots growing in to a portion of the sewer pipe. He cleaned the pipe as best he could at the time and indicated we would need to dig up the line to determine the problem. He scheduled the work and contacted all of the local departments to have the area properly marked before digging. This included the City of Bonners Ferry Water, Sewer, and electrical departments. KG&T returned on April 7, 2015 to begin the inspection and repairs. Because there was work done in the area by a company known as Earth-works, and both I and KG&T were aware of prior problems, I requested that he proceed carefully so that I could document any problems observed.

As digging begun the first observation was a buried flag marking where Earth-Works had been digging. (Exhibit 6).

When KG&T reached the sewer lines several problems were immediately obvious. Exhibit 4 shows 2 of 3 junctions on the north end of where an improper repair was made by Earth-works. They broke my sewer line going to the City's main line and used a broken piece of clay pipe along with a short piece of sewer pipe to make the repair. They also used a 4 inch coupler on the end of my pipe to try to get it to fit into the broken piece of clay pipe. See exhibits 4 and 5. It is obvious in exhibit 4 that the pipe has also settled causing the junction to leak and allow roots to enter the pipes. It also shows that the "bell" end of the clay pipe was cracked which may have added to the problems.

At the south end of the repair there were 2 obvious problems. In exhibit 1 the blue pipe has settled and is running up hill to the city's main line. This has also caused an offset lip where the lines should come together. Sewer leakage was obvious at this location also. These can be seen in exhibit 1. After removing the improper patch it was noted that the broken clay pipe had not been properly cut off to a flat smooth edge, but was instead left broken and jagged. This can be seen in exhibit 2.

In approximately 2010 a company named "earth works" was hired by the city of Bonners ferry to perform a water line upgrade in various areas of the city. This work was performed on Chippewa Dr. and Caribou st. where our sewer line attaches to the city main line. Kg & t indicated that it was obvious that the contractor had hit and broke our sewer line. They repaired the line by splicing in a 6 foot section of pipe to a 15 inch section of clay pipe and then to my line. They used improper connections. They used broken pieces of pipe to cobbled together a faulty patch. They did not compact the ground under the repair and it settled causing additional problems. Kg & t has now properly repaired the break and connections using 1 single length of pipe. They compacted the soil beneath the patch and added proper base below it.

---

I hereby certify that I have read the above information and it is true and correct to the best of my knowledge.

I hereby make claim against the City of Bonners Ferry Idaho for the damages described above and for the repairs in the amount of $1770.80

Signature:________________ Date: April. 9, 2015

**Attached Exhibits**
**Photo 1 South end of earth works repair pipe offset.**
**Photo 2 South end of earth works repair showing broken jagged pipe.**
**Photo 3 South end of earth works repair below grade of main line.**
**Photo 4 North end of repair showing cracked bell and pipe splices.**
**Photo 5 North end of repair showing root damage in improper splice.**
**Photo 6 Shows old flagging buried above gas line above break repairs.**
**Bills from KG & T**

KG & T SEPTIC INC.

172 SUNRISE ROAD
BONNERS FERRY, ID 83805

Phone # 208-267-5110 kgtseptic@frontier.com
Fax # 208-267-6016

| Date | Invoice # |
|---|---|
| 4/7/2015 | 2720 |

| Bill To |
|---|
| GENE OVERMAN<br>6601 CHIPPEWA DR.<br>BONNERS FERRY, ID 83805 |

| P.O. No. | Terms | Project |
|---|---|---|
| 6601 Chippewae | Due on receipt | |

| Quantity | Description | Rate | Amount |
|---|---|---|---|
| | Excavation and labor to locate and dig up faulty sewer line. Patch, add cleanout down by street for any further problems. Back fill, compact, and cleanup. | 1,538.53 | 1,538.53 |
| | 4" Abs pipe, concrete, fittings | 148.37 | 148.37T |
| | Sales Tax | 6.00% | 8.90 |

| | | | |
|---|---|---|---|
| Thank you for your business. | 3% will be added to the total price if paying with a credit card. | Total | $1,695.80 |

KG & T SEPTIC INC.

172 SUNRISE ROAD
BONNERS FERRY, ID 83805

Phone # 208-267-5110 kgtseptic@frontier.com
Fax # 208-267-6016

PAID
03/23/2015

| Date | Invoice # |
|---|---|
| 3/23/2015 | 2642 |

| Bill To |
|---|
| GENE OVERMAN<br>6601 CHIPPEWA DR.<br>BONNERS FERRY, ID 83805 |

| P.O. No. | Terms | Project |
|---|---|---|
| | Due on receipt | |

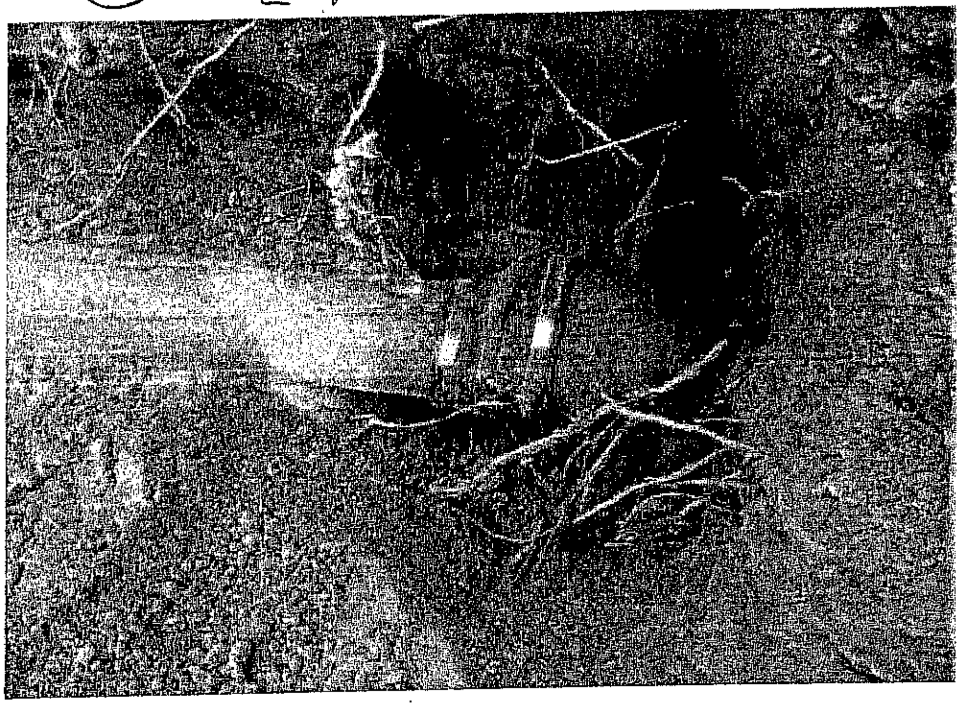
| Quantity | Description | Rate | Amount |
|---|---|---|---|
| | CAMERA LINE | 75.00 | 75.00 |
| | Sales Tax | 6.00% | 0.00 |

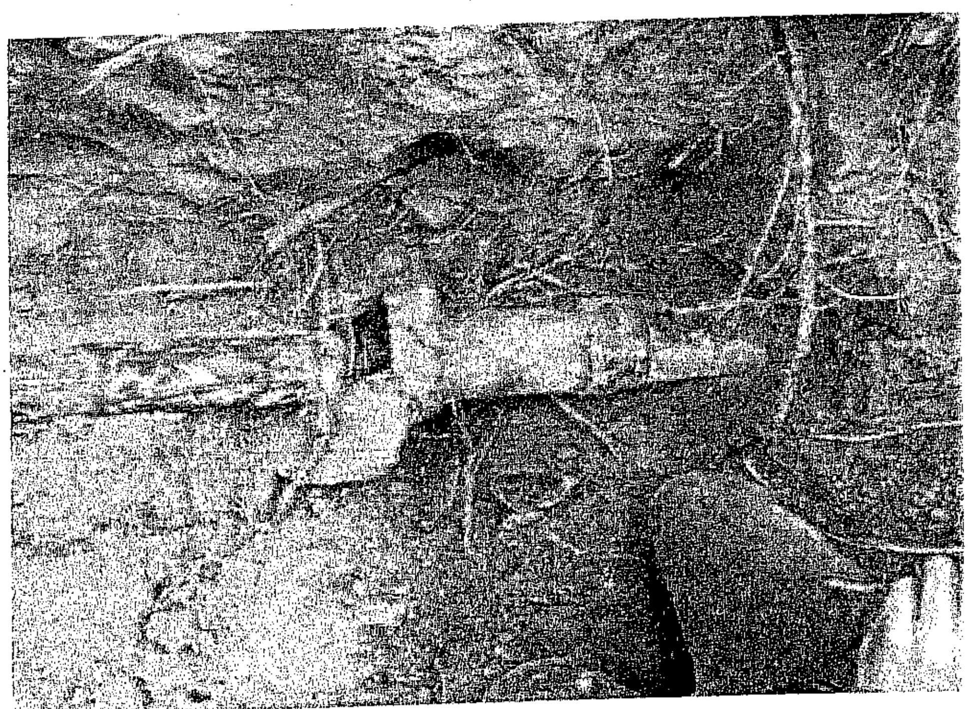
| | | | | |
|---|---|---|---|---|
| Thank you for your business. | 3% will be added to the total price if paying with a credit card. | | Total | $75.00 |

I (1)

J (2)

3 E ✓





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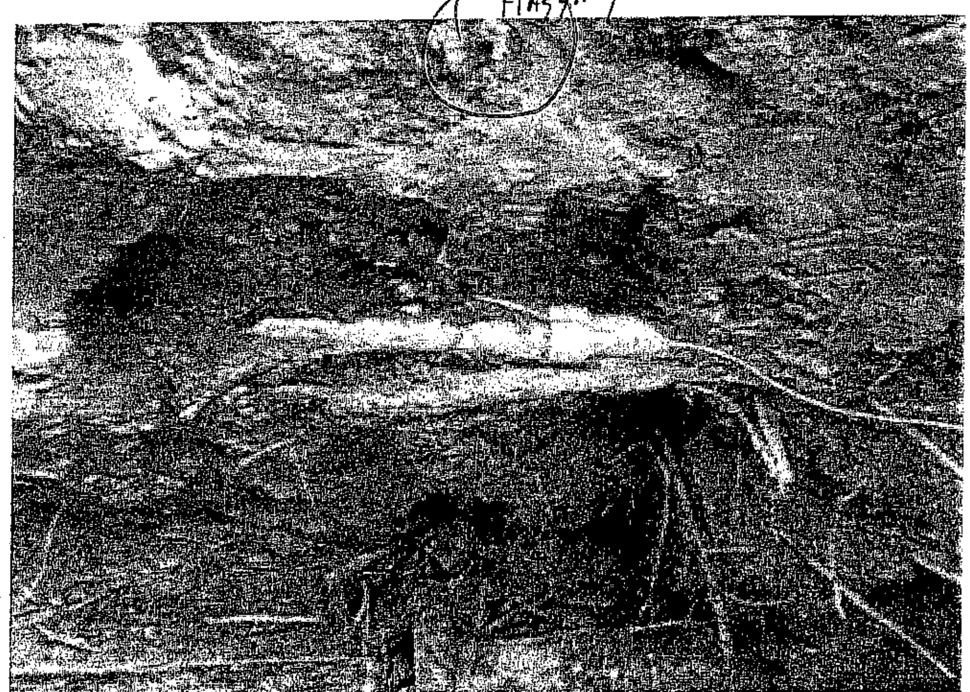
FLAGGING



V H. 6

# MEMO

CITY OF BONNERS FERRY
CITY ADMINISTRATOR

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Date: 17 April 2015
To: City Council
From: Stephen Boorman, City Administrator
Subject: Distributed Generation and Organized Power Markets.

Following is some background information for a short overview I will provide during my report. The amount of distributed generation and the organized power markets will have an impact to the power prices we pay. It is also an emerging trend that should be considered when setting electric rates.

Thanks

SJB

# Presentation to P[illegible]

March 4, 2015

powerex. 25 YEARS

Supply. Flexibility. Commitment

# Disclaimer

Powerex is committed to full compliance with laws and regulations, including federal and state antitrust laws.

Powerex, the merchant arm of BC Hydro, is here as a market participant within the WECC and active participant in EIM discussions.

Powerex is here to discuss regulatory and market design issues only, including those related to BPA and CAISO tariff provisions as well as current EIM initiatives underway.

Powerex is not here to discuss any topics or share information that may constitute or result in possible anticompetitive behavior, and will not share non-public information regarding its pricing, supply, capacity, bids, costs, customers, or strategic plans.

Powerex understands and expects that any views, opinions or positions presented or discussed by meeting participants during this session are the views of the individual meeting participants and their organizations, and are not intended to represent an agreement between meeting participants.

# Energy Imbalance Markets / SCEDs
## What are they trying to achieve?

**Today's world in the NWPP**

- Active trading and scheduling *generally* achieves efficient generation / transmission use
  - But largely limited to <u>hourly</u> granularity
    - Fifteen minute scheduling recently enabled, but low trading liquidity

- Intra-hour imbalances
  - Difference between scheduled hourly load and actual load
  - Difference between scheduled hourly VER output and actual VER output
  - Imbalances served within each Balancing Authority Area (BAA) independently
    - Able to "net" imbalances <u>within</u> BAA, but not <u>between</u> multiple BAAs
    - Each BAA's net imbalances generally served by BA's set aside dispatchable resources

*The mass installation of VERs has resulted in growing concerns that today's framework for meeting intra-hour imbalances is highly inefficient and must change.*

# Energy Imbalance Markets / SCEDs
## What are they trying to achieve?

**Centralized Visibility and Dispatch**

1. Diversity of imbalances across multiple BAAs
   - Energy efficiency – allow offsetting imbalances to net each other
   - Capacity efficiency – avoid carrying duplicative balancing reserves, diversity *may* reduce total balancing reserves necessary to maintain reliability

2. Least-cost dispatch
   - Meet the <u>net</u> multi-BAA imbalance from lowest-priced resources, not just from specific balancing reserves set aside
     - IPPs within BAA, resources in other BAAs
   - Additional, mutually-beneficial trading opportunities that bilateral trading may miss
     - Reduce Dispatchable Gen A and increase Dispatchable Gen B
     - May occur on 5 minute, 15 minute, or hourly basis

3. Other features of many EIMs / SCEDs
   - Actual flow model instead of contract path improves transmission utilization
   - Centralized "unit commitment" – dispatch thermal units to start-up and be ready
   - Congestion relief – use EIM / SCED to re-dispatch resources to resolve congestion



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## CAISO EIM – What are the potential benefits?

1. Diversifies imbalances across multiple BAAs
   - Energy and capacity efficiencies possible through "netting" offsetting imbalances
2. Least-cost dispatch
   - 15-minute and 5-minute granularity
   - Provide least-cost approach to meet net imbalances
3. Unit commitment
   - Position and start flexible resources
4. Actual flow model and congestion relief
   - Improved modelling of transmission network leads to more efficient utilization
   - Use EIM to re-dispatch generation to resolve congestion
5. Low cost and fast implementation
   - Leverages existing software, processes, staff of CAISO
   - No *explicit* exit fee
6. Potential for coordinated dispatch across Western Interconnection under a single EIM

## CAISO EIM – What are the key concerns?

1. Governance
   - Conflicts of interests between PNW ratepayers and California stakeholders
     - Equitable compensation for reliance on flexible generation assets
     - Allocation of transmission costs and benefits
   - Goes beyond formal governance model – software, processes, staff decision making
2. Resource Sufficiency
   - Design permits insufficient procurement of flexible reserves
   - Permits "leaning" on flexible generation assets in neighboring BAAs
     - Increases reliability risk
     - Denies equitable compensation for flexibility
3. Free export (and wheel-through) transmission service
   - Highly beneficial to large importing BAAs
   - Shifts fixed costs of transmission onto load in exporting BAA
4. Pre-mature expiration of the value of OATT rights prior to EIM timeframe each hour
   - Confiscates congestion value of transmission investments to "make way" for EIM

## CAISO EIM – What are the key concerns?

5. VER integration costs shifted onto local load
   - Cost for committing flexible generation capacity not currently allocated to VERs
   - Load in BAA where VER is located may fund the costs, even if VER is exported
   - Contrast to BPA, which currently charges both a capacity charge (VERBS) and energy charge (Schedule 9)
6. Market Monitoring / Price Mitigation
   - Department of Market Monitoring is a division of CAISO
   - Automatic mitigation can over-ride offer prices and dispatch units anyway

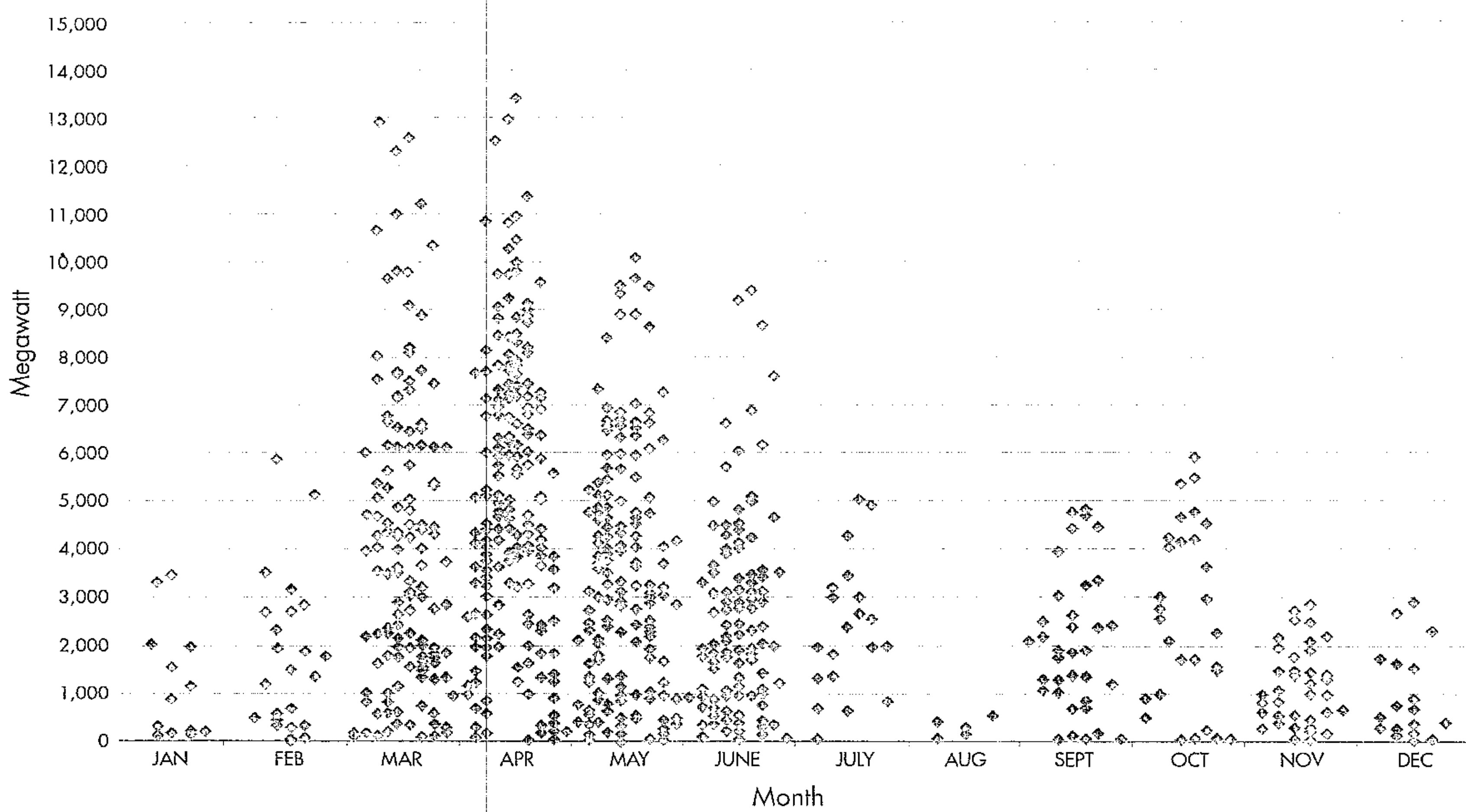
# Closing Remarks

- We share CAISO's stated objectives of improved reliability and efficiency

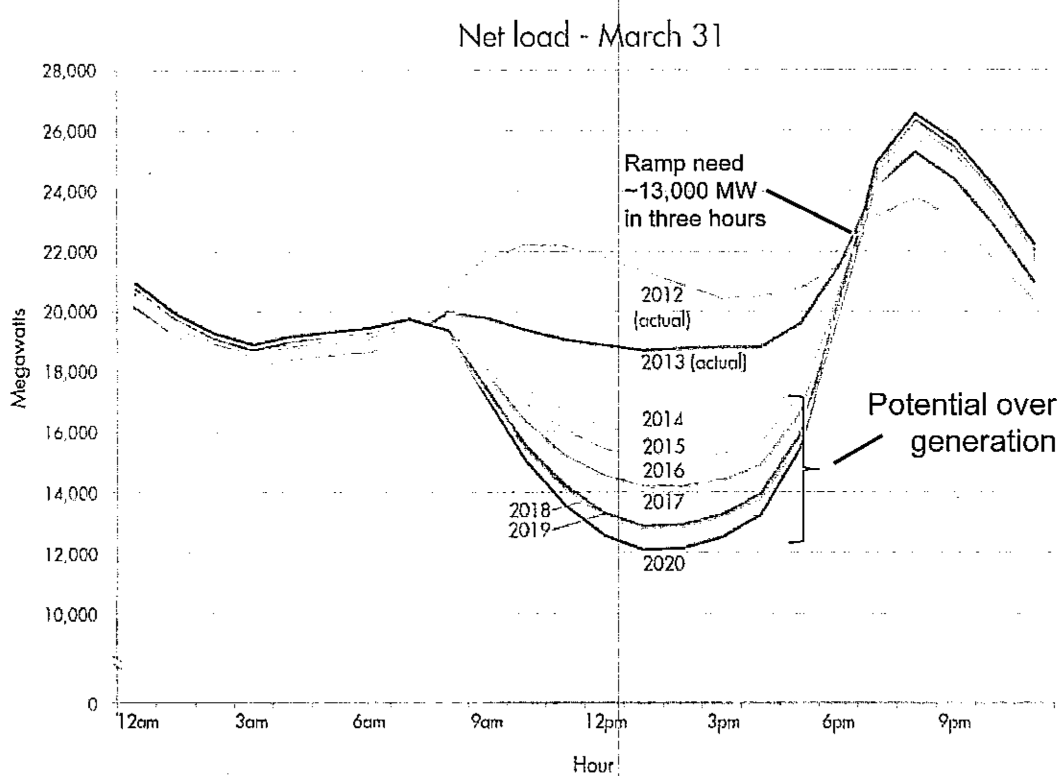
- But CAISO's market design choices will *also* result in large shift in the allocation of costs and benefits of generation and transmission investments
  - Initial design choices
  - Early public information on operations reinforces this concern
  - Cannot be addressed by formal governance changes alone

- *Status quo* is not an option for the Northwest
  - CAISO EIM approach will affect the NW, and impacts will be widespread
    - Experience tells us that intra-hour markets affect the valuation and use of resources across all timeframes, including resources not directly participating in that market
    - If we do nothing, NW markets will be increasingly designed, operated and governed by CAISO
  - A solution designed and governed by the NW can protect our ratepayers' interests today and in the future

# CAISO RPS Curtailment in 2024 – 40% RPS Scenario

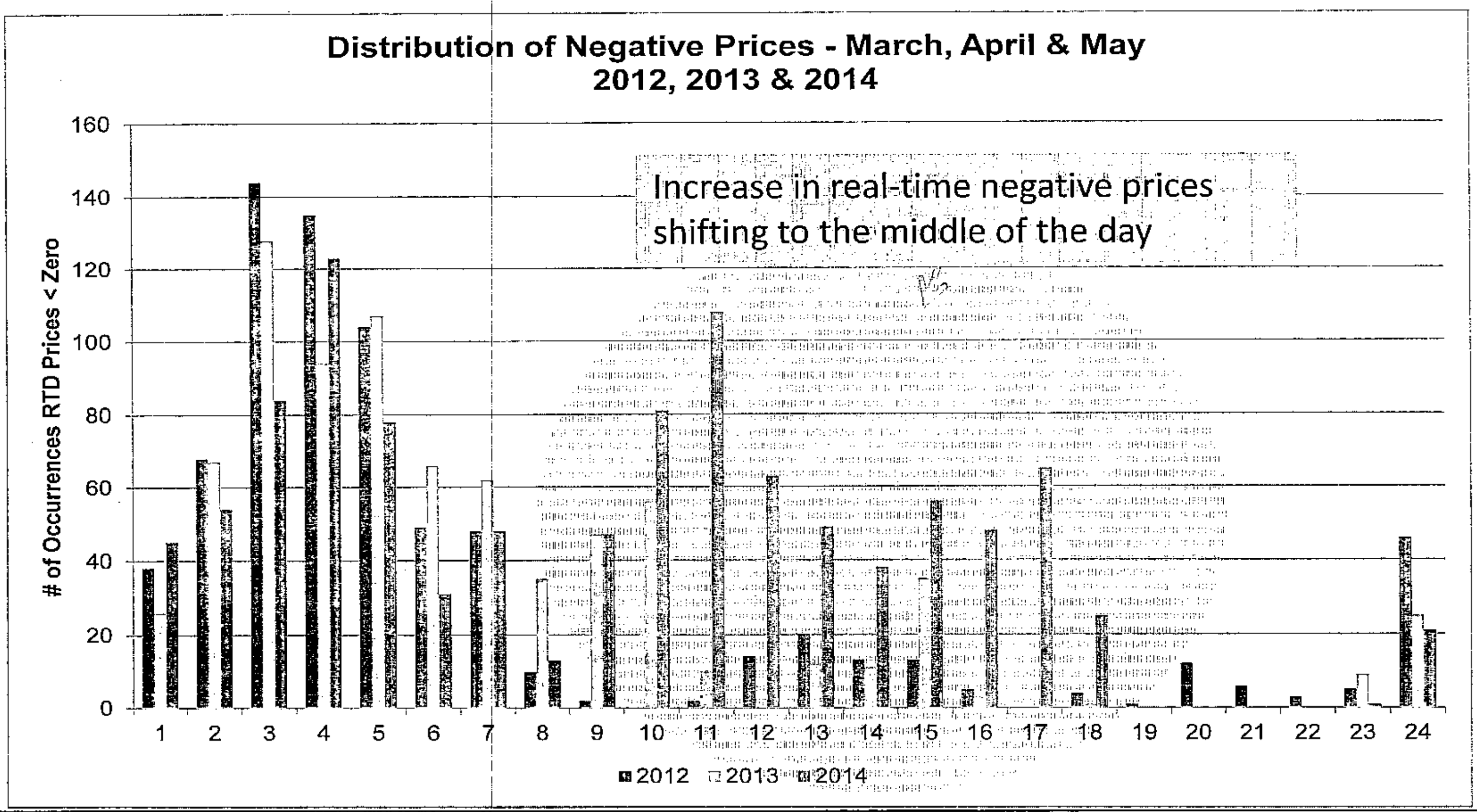


# Non-Flexible resources create over-generation conditions and potential for RPS curtailment




- ISO has already seen the need to curtail generation in 2014.
- Overgen may lead to curtailment because of dispatch limitations on some resources, such as:
  - Geothermal
  - Nuclear
  - Small hydro
  - Combined heat and power
- Operational requirements include:
  - Minimum gas necessary to provide ramping
  - Necessary ancillary services
  - Load following

# Negative energy prices indicating over-generation risk start to appear in the middle of the day.

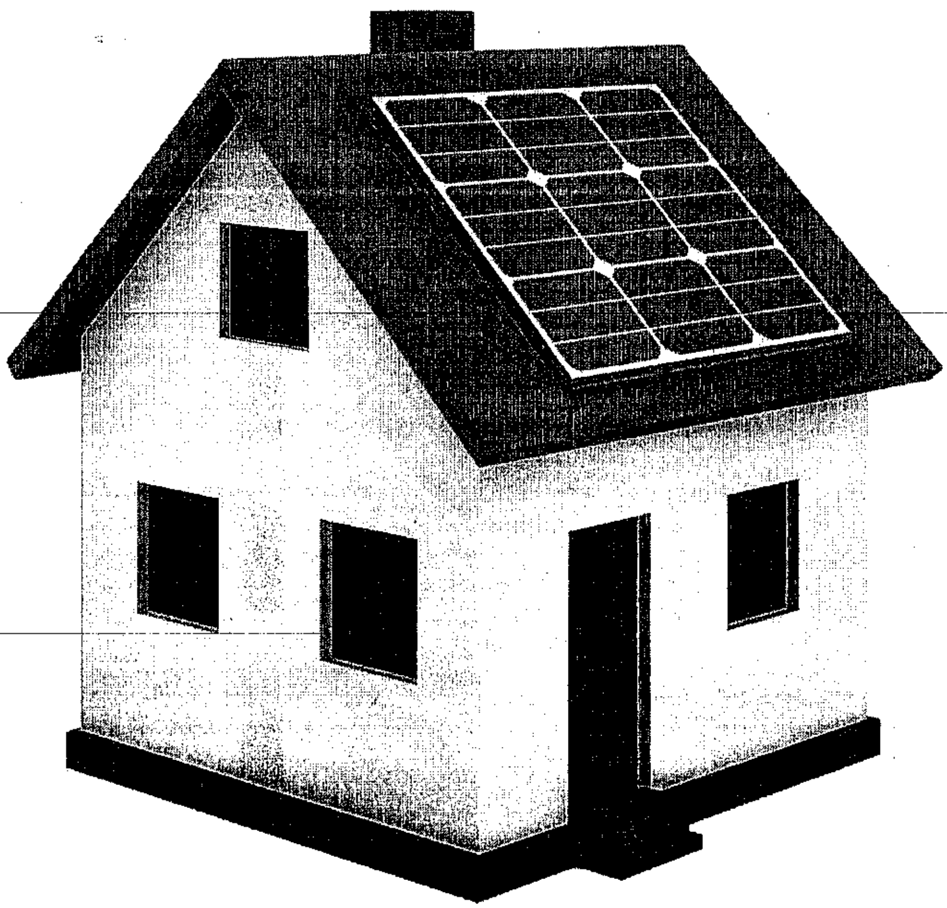


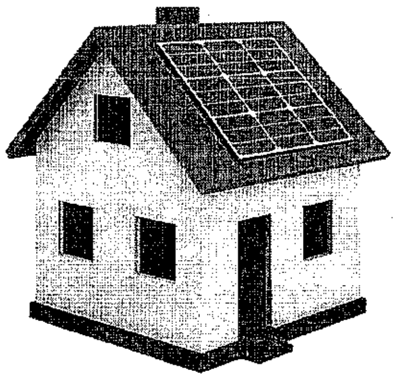
APPA® American Public Power Association

# Distributed Generation

## An Overview of Recent Policy and Market Developments

November 2013





# Distributed Generation

An Overview of Recent Policy and Market Developments

November 2013

American Public Power Association

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## Contents

## Introduction

The number of residential and commercial customers who have installed solar generating panels at their homes and businesses has increased in recent years. Motivated by environmental concerns and a desire to reduce their electric bills, these customers have spurred a dramatic increase in the amount of distributed generation (DG) in the United States. Advances in solar photovoltaic (PV) technology, combined with decreasing capital costs and construction subsidies, have further sparked the construction of new capacity.

The advance of DG as a complement to traditional electric service has potential benefits for electric utilities. Customers producing rather than consuming electricity at peak demand times mitigate the need to construct new generating capacity. Consumption of generation near its source could lead to lower transmission and distribution line losses and has other potential benefits for distribution and transmission systems.

DG also poses many operational challenges to electric utilities. Generators must still rely on the electric grid for backup service during periods when they are not meeting all of their electricity needs (e.g., during the early morning and evening hours, during prolonged overcast conditions, during periods of unexpected PV installation failure, etc.). The variability of PV solar generation creates further challenges in maintaining system balance. There are also safety issues involved with customers having on-site generation, as power from DG installations can back-feed into distribution systems and cause occupational hazards for lineworkers.

DG installations also pose revenue challenges for electric utilities. Because DG customers are typically compensated at times when they provide excess power to the grid and charged when they consume power from the utility, their electric bills potentially net to zero, and in some cases their net balance over the relevant billing period may even be negative, meaning the utility must pay the customer. Since residential electric bills are based primarily on electric consumption, and the associated customer charges rarely reflect the full amount of fixed costs utilities incur to provide retail electric service, utilities could face a revenue shortfall. As a result, other retail customers ultimately subsidize those customers with distributed generation or the utility under-recovers the cost of providing service.

This paper examines the many challenges that DG poses, as well as ways utilities can address these challenges and encourage DG development without unduly burdening other customers or adversely impacting utility operations and fiscal stability. The first section provides background on what DG is and the different pricing mechanisms utilities are using to compensate distributed generators. The second section explores the operational impacts DG has on the electric grid as well as the costs and benefits of DG for the distribution and transmission systems. The third section discusses the financial implications of DG, and ways different utilities have attempted to mitigate its impact on their bottom lines. The final section details the types of programs and rates public power utilities have implemented to ensure rate equity.

## I. Distributed Generation, Net Metering, and Feed-in Tariffs

### What Is Distributed Generation?

Distributed Generation refers to power produced at the point of consumption. DG resources, or distributed energy resources (DER), are small-scale energy resources that typically range in size from 3 kilowatts (kW) to 10 megawatts (MW) or larger. A typical household's peak demand is about 3.5 kW, so the smaller resources are used by residential customers, while the larger systems are typically used by commercial and industrial customers. In addition to PV, DERs can include small wind turbines, combined heat and power (CHP), fuel cells, microturbines, and other sources. More than 90 percent of installed distributed generation in the United States today is solar. Therefore solar is the primary focus of this paper.

The definition of DG has evolved over time. When the Public Utility Regulatory Policies Act (PURPA) was enacted in 1978, utilities became statutorily obligated to purchase power from qualifying facilities (QFs) at the utility's "avoided cost," (defined as the cost of the utility's incremental cost for its next block of power). These QFs included CHP facilities and small power production facilities with 80 MW or less of installed renewable generation capacity.[1] These QFs were generally thought of as DG facilities. Later on, however, the California Public Utilities Commission (CPUC), for purposes of establishing a roadmap for rulemaking regarding DG, defined DG as "small-scale electric generating technologies installed at, or in close proximity to, the end-user's location."[2]

Some definitions of DG turn on location rather than size. The Swedish Royal Institute of Technology's Department of Electric Power Engineering defines DG as "an electric power source connected directly to the distribution network or on the customer side of the meter."[3] Both this definition and the CPUC definition cover the types of distributed resources discussed in this paper.

### Compensating DG Supply

Though utilities have developed varying formulae for compensating distributed generators for the generation that flows onto their grids, there are two basic methods of compensation: net metering and feed-in tariffs.

### Net Metering

Under net metering programs, customers with on-site generation are credited for the amount of kilowatt-hour (kWh) sales sold back to the grid and are charged for periods when their consumption exceeds their generation. To put it another way, their meters literally run backwards when a DG unit is producing more power than the customer is using. Utilities then charge the net difference between consumption and generation.

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[1] Itron, Inc. *Impacts of Distributed Generation, Final Report.* Prepared for the California Public Utilities Commission Energy Division Staff, January 2010, p. 3-1.

[2] Ibid., p. 3-2.

[3] Ibid.

There are different mechanisms for billing customers. If a customer has a negative net balance, that balance may carry forward to the next month. Most utilities have a "true-up" period (at the end of the year, or some other pre-determined time). In some circumstances, a customer with a negative net balance may be compensated for its excess generation, while in other situations the balance reverts to zero at the end of the designated period.

State policies on net metering also differ. Some states limit the technology and fuel types eligible for net metering. Many states also cap the total generator capacity eligible for net metering, placing caps on both individual generators and aggregate load eligible for net metering.[4]

Under most net-metering programs, the customer is both charged and credited at the utility's full retail rate of electricity. The meter simply records how much energy is consumed on-site and then how much is sold to the grid, with the difference in kilowatt-hours either charged or credited to the customer. Since net metering generally does not account for time of usage, it potentially over-compensates distributed generators and credits them with a value of generation that is higher than the utility's avoided cost.

### Feed-in Tariffs

Some states and utilities have mandated feed-in tariff (FIT) programs. A FIT is a long-term contract under which the utility agrees to purchase the excess generation from a distributed generator or DER. The utility establishes a per-kWh purchase price. This rate varies from utility to utility and is a source of much contention (explored below). Ultimately, utilities pay distributed generators as they would a non-utility wholesale power producer.

FITs have been employed more commonly in Europe than in the United States, but they are seen as a means of incentivizing more DG. Though similar to net metering, under a FIT the generator is compensated at the predetermined rate for the excess generation supplied *to* the grid, while its purchases *from* the grid are charged at the retail rate.[5] In other words, the FIT rate can be higher or lower than the retail rate. Some early adopters of FITs, both in Europe and the United States, intentionally set rates high in order to encourage the development of distributed resources. Other utilities have chosen to set rates closer to the wholesale purchase price of electricity – and thus closer to the avoided cost level.

Some utilities have developed a blend of net metering and FITs, crediting distributed generators at less than the retail rate for electric service. Still other utilities have attempted to develop a tariff that more accurately reflects the value of DG for their system. These "value of solar" tariffs have been implemented by utilities such as Austin Energy in Texas and are discussed at greater length below.

### PURPA

PURPA adds another complication to FITs. Under Section 210 of PURPA, utilities are required to purchase power from QFs. PURPA mandates that any rate set under PURPA cannot exceed the avoided cost. PURPA defines avoided cost as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility

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[4] See Energy Information Administration (EIA) article, "Policies for compensating behind-the-meter generation vary by State," May 9, 2012. Accessed at: http://www.eia.gov/todayinenergy/detail.cfm?id=6190.

[5] For more information see EIA article, "Feed-in tariff: A policy tool encouraging deployment of renewable electricity technologies," May 30, 2013. Accessed at: http://www.eia.gov/todayinenergy/detail.cfm?id=11471.

would generate or purchase from another source."[6] The Federal Energy Regulatory Commission (FERC) later added in its decision in the *Southern California Edison* case[7] that "externality adders," such as the value of reduced air emissions, could not be included in the avoided cost calculation. Furthermore, certain exemptions from the obligation to purchase power from QFs exist under PURPA. In some regional transmission organizations (RTO), QFs with greater than 20 MW capacity are presumed to have "non-discriminatory access," and thus utilities may apply to FERC for an exemption from their obligation to purchase the surplus power.[8]

Though FERC's ability to set wholesale electric power rates under the Federal Power Act (FPA) is limited to "public utilities," (i.e., generally investor-owned utilities, or IOUs), the "must purchase" provisions of Section 210 of PURPA are applicable to all "electric utilities," including publicly owned electric utilities and rural electric cooperatives.[9] Therefore, public power utilities are subject to the same restrictions as IOUs and other utilities in setting avoided cost rates in compliance with PURPA. Further, if a distributed generator makes a sale of electric power to a public power utility and the rate is not PURPA-compliant, then as a legal matter, the sale transaction is considered a "sale for resale" (a wholesale sale) of electric power under the FPA and the entity that makes such a sale must submit to FERC regulation under the FPA.[10]

For a rate to be compliant with PURPA, the rate must be set at the avoided cost. Some have argued, however, that an avoided cost rate might be too low to encourage installation of DERs. Utilities might be able to structure their FITs in order to avoid FERC jurisdiction.[11]

## The Current DG Marketplace

The amount of DG, particularly solar PV, has risen sharply in the United States over the past few years. As of 2011, 4 gigawatts (GW) of distributed capacity had been installed in the United States,[12] with 200,000 residential electric customers owning at least some PV capacity. The

[6] Federal Register. 12214-12237 (1980), as cited in Justin Wynne. *Feed-in Tariffs and Implications for Public Power*. Memphis, TN: APPA Legal Seminar, November 29, 2011, p. 13. Accessed at: http://www.publicpower.org/files/LegalSeminar/Wynne.pdf

[7] 70 FERC ¶61, 215 (1995), as cited in Wynne.

[8] Wynne, p. 14.

[9] Ibid., p. 15.

[10] This issue does not arise in the context of net metering because FERC has held that no jurisdictional sale of power takes place. In *MidAmerican Energy*, 94 FERC¶61,340 (2001) and *Sun Edison LLC*, 129 FERC ¶61,146 (2009), FERC held no FPA-jurisdictional sale takes place when a generator participates in a net metering program if, over the course of a retail billing period (e.g., a month), there is no net delivery of energy from the generator to the grid. Both orders make clear the holdings apply to both QFs and non-QFs participating in net-metering programs.

[11] See ,for example, Scott Hempling, et al., *Renewable Energy Prices in State-Level Feed-in Tariffs: Federal Law Constraints and Possible Solutions*, January 2010. Hempling offers three alternative methods to pay generators at higher than the avoided cost: awarding the generator renewable energy credits (RECs); offering tax credits equal to the amount paid at above avoided cost; or using funding from sources such as tax credits, grants, and loans. These proposals, however, have not been tested in court proceedings and it is unclear whether they would comply with PURPA.

[12] Tom Stanton. *State and Utility Solar Energy Programs: Recommended Approaches for Growing Markets*. Silver Spring, Md.: National Regulatory Research Institute, 2013, p. 5.

amount of distributed capacity is expected to increase to approximately 9 GW by 2016, and to as much as 20 GW by 2020.[13]

One of the main drivers for this increased capacity is the declining cost of solar panels. Solar panel costs have fallen from $3.80 to 86 cents per watt as of 2012.[14] This, in turn, has led to a reduction in total solar installation costs. Solar installation costs have decreased 70 percent since 2008 and are still falling.[15] In 2012 alone, prices dropped an average of 14 percent. The price fell by 90 cents per watt for small systems (10 kW or less), 80 cents per watt for mid-sized systems (10-100 kW), and 30 cents per watt for larger systems (greater than 100 kW). The average price for a small system is now $5.30 per watt.[16] Installation costs vary throughout the country and are as low as $3.90 per watt in Texas.[17]

American customers have largely benefitted from developments in the European marketplace. The rapid expansion of solar DG led to an expansion in worldwide solar module manufacturing, which in turn led to reduced costs. The increase in American PV installations coincided with the bottoming out of module prices, meaning that American customers are paying far less than European customers did at the time of peak European expansion.[18]

In addition to declining panel prices, there are state, federal, and even utility incentives for solar panel installations. The current federal tax credit for installing PV panels is 30 percent of total installed costs. In some states, customers receive an additional 30 to 40 percent tax credit. For example, the combined federal and state tax credits for a North Carolina resident mean that the government is covering 70 percent of the total costs for installing solar paneling.[19]

The Edison Electric Institute (EEI) notes several other reasons for the increased reach of solar distributed generation:

- Increasing utility rates (particularly tiered rate structures with higher rates in higher usage tiers) make self-generation more viable for rate-payers.
- Renewable portfolio standards, in place in 29 states plus the District of Columbia, encourage development of more PV resources.
- Time-of-use rates, which set higher rates for consumption during peak-demand hours, create further incentives for installing distributed solar PV.[20]

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[13] Edison Electric Institute. *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, 2013, p.4. Some estimates of future growth are even more optimistic, with one analysis predicting 20-30 GW of new installed solar distributed capacity by 2017. See Andy Colthorpe, "US Solar capacity to total 50 GW by end of 2016, says Deutsche Bank." Accessed at: http://www.pv-tech.org/news/us_installed_capacity_to_total_50gw_by_the_end_of_2016_including_20gw_to_30.
[14] Ibid.
[15] Travis Bradford and Anne Hoskins. *Valuing Distributed Energy: Economic and Regulatory Challenges*, Columbia University and Princeton University, 2013, p. 5.
[16] Galen Barbose, Naim Darghouth, Samantha Weaver, and Ryan Wiser. *Tracking the Sun VI: A Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012.* Lawrence Berkeley National Laboratory, 2013, p. 1.
[17] Ibid., p. 2.
[18] Phillip Brown. *European Union Wind and Solar Electricity Policies: Overview and Considerations*, Congressional Research Service, August 7, 2013, pp. 33-34.
[19] Bob Curry. *The Law of Unintended Consequences.* Public Utilities Fortnightly, March 2013, p. 46.
[20] *Disruptive Challenges*, p. 4.

EEI concludes that a 10 percent reduction in load due to DER would lead to a 20 percent increase in rates for non-DER customers. This combination of increasing electric rates with falling PV costs could lead to greater market penetration throughout the country for solar DG. Though the variability of solar DER resources means customers will remain tied to the grid for some time, the development of improved battery storage technology, fuel cells or micro turbines could eventually allow customers to become totally grid-independent.[21]

It will likely take quite some time for the most aggressive predictions to come to fruition. Even under optimistic projections of potential distributed capacity installations, distributed PV would represent only a small fraction of total U.S. electric generating capacity. Moreover, solar and other renewable resources are not viable in all parts of the country, even if there is further development of energy storage technologies. However, even minimal DER market presence can have significant impacts on utility system reliability and revenue streams. The rest of this paper will closely examine the potential impacts and ways that utilities can ameliorate them.

[21] Ibid., p. 5.

## II. The Impact of Distributed Generation on the Electric Grid

Proponents of DG tout a number of ancillary benefits. Since DG is consumed largely on site, it would presumably lower distribution, transmission, and generation infrastructure and operating costs. Another advantage of the electricity being consumed closer to its source would be a reduction in electric line losses.

A study commissioned by the Solar Energy Industries Association (SEIA) looked at the benefits and costs of solar DG for Arizona Public Service (APS).[22] The study attempted to place a monetary value on the costs and benefits of DG on the APS system. Among the benefits of DG this study posited:

- Avoided generation capacity costs. Increased level of DG penetration could reduce the need for new generation assets. Higher levels of DG penetration would especially displace new, natural gas-fired generation.
- Avoided ancillary services. The Western Electricity Coordinating Council (WECC) requires utilities to maintain spinning reserves of at least 7 percent of load. Load reductions attributable to DG would mean APS would have to procure fewer reserves.
- Avoidance of higher transmission costs. In addition to demand response (DR) and energy efficiency (EE), DG would help reduce APS's peak demand by 1,150 MW in 2017. This would negate higher transmission costs due to increased demand.
- Environmental benefits. Since DERs are generally non-emitting, renewable resources, they would displace fossil fuel energy, thereby reducing greenhouse gas emissions as well as emissions from sources such as $SO_2$ and NOx.
- Avoided renewable costs. Though APS has procured enough renewable resources to meet the state's renewable energy standard (RES) requirements, DG could be a hedge against the failure of those resources, particularly those that have not yet come on line.
- Grid security. Since DG capacity is dispersed throughout the utility's territory, it is unlikely that all generators would fail at the same time. Furthermore, since the end-user and producer are one and the same time, DG mitigates against outages due to transmission or distribution system failures.

Though this study concentrated on one utility service territory, most of these arguments about the advantages of DG are employed by DG advocates in other areas of the country. While there is some merit to these arguments, DG proponents have been known to overstate these benefits while minimizing or disregarding other risks. This section will detail some of the technical and operational challenges associated with DG.

### Interconnection

Distributed generators must enter into interconnection agreements with their local distribution utilities. These agreements lay out the technical parameters of the interconnections and usually

[22] R. Thomas Beach and Patrick G. McGuire. *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service.* Crossborder Energy, May 8, 2013.

require that feasibility studies be carried out to ensure that the proposed interconnection meets applicable safety and reliability standards. FERC has established standardized procedures for interconnecting small generators[23], but specific interconnection agreements vary among states and utilities.

California provides an example of one state's approach to interconnection. California issued Rule 21 in order to streamline the interconnection process. The state issued the California Interconnection Guidebook[24] to offer guidance to DG customers and utilities. Though Rule 21 applies only to utilities under the jurisdiction of the CPUC (IOUs), many publicly owned electric utilities modeled their rules after Rule 21.

Under Rule 21, a customer wishing to interconnect has five options:

1. Isolated operation, unconnected to the utility's distribution system.
2. Interconnected but not exporting power to the distribution system.
3. Interconnected and incidentally exporting power.
4. Net energy metering.
5. Exporting power for sale.[25]

"In each of the last four relationships, the generator operates 'in parallel' with the utility's distribution system, generating power while interconnected, and thus having to match the utility power characteristics."[26] Most generators fall into these latter groupings and as such must match utility voltage characteristics and meet certain minimum power requirements.[27]

Generators seeking to interconnect with a utility's distribution system are graded on a pass/fail basis in their initial review based on whether the proposed generator is likely or not to damage the distribution system or disrupt its operation. If a generator fails the initial screen, a supplemental review is conducted to see if the issue can be addressed with minor alterations.[28]

Rule 21 lays out further technical specifications. Applicants must provide detailed specifications, including net nameplate rating, operating voltage, and power factor rating. Rule 21 and the accompanying guidebook also lay out procedures for the utility to follow in the screening process, and even offers model agreements from utility examples.

Other states offer similarly detailed guidelines for interconnection. Though both the federal and state parameters have helped to keep distribution grids stable as more DG resources are

[23] Federal Energy Regulatory Commission. *Standardization of Small Generator Interconnection Agreements and Procedures.* Docket No. RM02-12-000; Order No. 2006, May 12, 2005. FERC procedures apply to FERC-regulated "public utilities" (generally IOUs) that own, control, or operate facilities used for transmitting electric energy in interstate commerce. A non-public utility (for example, a public power utility) that seeks voluntary compliance with the reciprocity conditions of a FERC-regulated public utility's open access transmission tariff may satisfy that condition by adopting these procedures and form of agreement.

[24] Chris Cooley, Chris Whitaker, and Edan Prabhu. *California Interconnection Guidebook: A Guide to Interconnecting Customer-owned Electric Generation Equipment to the Electric Utility Distribution System Using California's Electric Rule 21.* Consultant Report prepared for California Energy Commission, Public Interest Energy Research Program, September 2003. Available at: http://www.cpuc.ca.gov/PUC/energy/DistGen/.

[25] Ibid., p. 7.

[26] Ibid.

[27] Ibid., p. 8.

[28] Ibid., p. 16.

integrated, the further expansion of distributed resources may cause complications down the road. As expressed in joint comments filed by three utility trade associations with FERC:

> For example, if a 2-MW retail project request comes in simultaneously with a 2 -MW wholesale project request, and both projects seek to interconnect at the same line section and both require the same line capacity, the utilities in these jurisdictions must choose to connect one project over the other because of the limited line capacity. Although Transmission Providers and electric utilities in these jurisdictions have created elaborate systems to limit the potential for such situations, this kind of scenario will increase with the growth of small generation interconnection requests and is already causing increased concern among electric utilities.[29]

## System Balance

Another challenge that DG presents to the electric grid is maintaining system balance. A Massachusetts Institute of Technology (MIT) study on the future of the electric grid explains that low levels of DG penetration merely reduce load at the nearby substation, but high DG penetration could create excess load at the substation. This would cause power to flow from the substation to the transmission grid, creating a reverse power flow that grids are not designed to handle. This could lead to high voltage swings and other stress being placed on electric equipment. These potential strains on the system will require utilities to make further capital investment in system upgrades.[30]

Some standards currently exist to address these variable voltage situations. The Institute of Electrical and Electronics Engineers (IEEE) created IEEE Standard 1547 to ensure that DG customers do not negatively impact other customers or the grid. It requires that no objectionable "flicker" occur for other customers due to voltage variation. It also enumerates safety standards, particularly standards requiring that DG units disconnect when local faults occur. It also requires DG units to detect unintentional islanding, where DG systems supply a localized section of the grid that has been disconnected from the larger grid system.[31]

Though the standard has been effective in securing lineworker safety and in maintaining grid balance, it is somewhat outdated. The standard was issued in 2003. With the growth of DG, the standard should be updated. For instance, as mentioned above, increased DG penetration could lead to greater voltage variability, and thus to an increased incidence of flickering; however, DG systems with voltage regulation capability could guarantee voltage stability. The current standard disallows voltage regulation at the interconnection point and thus needs modification.[32]

DG can also complicate fault detection. These units could potentially increase current at a fault while reducing it at the protection device. This makes it harder to detect a fault and disconnect the unit. Changing fault currents could also hamper how other protection devices function.[33]

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[29] Comments of the National Rural Electric Cooperative Association, Edison Electric Institute, and American Public Power Association on the Notice of Proposed Rulemaking to Update the Small Generator Interconnection Rules and Procedures. *Federal Energy Regulatory Commission, Docket No. RM13-2-000*, June 3, 2013, p. 29.

[30] MIT. *The Future of the Electric Grid.* Cambridge, Mass.: Massachusetts Institute of Technology, 2011, p. 17.

[31] Ibid., p. 112.

[32] Ibid., pp. 113-14.

[33] Ibid., p. 116.

## Safety Concerns and "Islanding"

There are other potential safety issues involving DG. Of particular concern is "islanding," where the DG unit continues to energize a feeder even though the electric utility is no longer supplying power due to an outage or other cause. This creates a very high safety risk to utility workers who might not realize that a circuit is still energized. DG units are required to "anti-island" and stop power generation once an islanding situation occurs, and as such have inverters that allow the unit to cease generation.

Even if islanding remains a remote possibility, there are other risks involved. It is possible for a high-voltage spike to occur, thus damaging other customer loads. The loss of the utility system reduces the impedance necessary for the PV inverters to function properly, leading to abnormal voltages before the inverter trips. This also potentially damages other loads.[34] Since the utility distribution system creates the sole ground source for a DG system feeder, the loss of grounding due to an outage could lead to overvoltage. This could damage both utility and customer equipment, especially surge protectors.[35]

Another consequence of islanding is out-of-phase reclosing. As General Electric explains, "If DG keeps the system downstream of a recloser or reclosing circuit breaker energized, the subsystem is likely to drift out of phase with the main system." Reclosing on an out-of-phase islanded system could damage the generator and could harm utility and other customer equipment under certain circumstances.[36]

Another remote consequence of very high DG penetration levels could be a system-wide blackout. If an area or region had a very high number of DG installations – on the order of 100,000 100-kW generators – and a bulk system event occurred that caused these DG systems to trip, it could have the same impact as losing a nuclear plant. One study posited that an initiating event that tripped these generators could lead to a blackout of the entire western interconnection.[37] Again, this could occur only with very high levels of DG penetration – on the order of 20 percent of system load.

## Impacts on Load and System Planning

In a certain sense, PV distributed resources provide a greater level of system protection, especially over large-scale utility PV installations. Since PV resources are generally distributed over a wide geographic area, intermittent cloud cover affects a smaller percentage of DG installations at one time, whereas cloud cover could adversely impact production at an entire utility-scale installation.[38] On the other hand, system operators do not have the ability to observe as closely the operation of DG systems. This particularly impacts load forecasting as system

[34] GE Energy. *Impact of Photovoltaic Generation on Distribution Systems*. Schenectady, NY: Distribution Systems Testing Application and Research, 2013, p. 59.
[35] Ibid.
[36] Ibid, pp. 60-61
[37] Ibid, p. 70.
[38] Ibid., p. 71.

operators cannot distinguish between increases in load due to higher demand and decreased solar output.[39]

The impairment of load forecasting capabilities is of increasing concern in the power industry. Distributed generation, along with utility-scale renewable resources and the increase in demand response resources, are all making load forecasting more difficult.[40] If load spikes more than expected when transmission and/or generation assets are down for service, this can lead to forced outages and blackouts. Though rare, this happened twice in 2013.[41]

Distributed resources especially impact system peak planning. Because DG customers – particularly those with PV installations – can shift the demand curve and shave peak usage, this may enable utilities to avoid adding peak generation resources; however, because these are localized resources, they "may shift the geographical areas of the grid requiring expansion, reinforcement, or upgrade."[42]

DERs also place increased strain on the distribution system. DG customers rely on the transmission, distribution and generation systems more than non-DG customers. DG customers use the distribution system for electric consumption when they are not producing power, and they also use the distribution system to carry away excess power. So, unlike traditional utility customers who use the distribution system one way, DG customers rely on the distribution system both for consumption and production. DG customers also rely on the system to maintain sufficient line voltage to support their activities.[43]

A study produced by Xcel, a Colorado-based IOU, rebuts or modifies some of the purported benefits of DG. For example, the report notes that while the immediate impact of DG is to displace coal fired units, in the longer term DG may displace more efficient natural gas units.[44] The highest levels of avoided costs occur in the first tranches of DG deployment as high-cost units are displaced; however, "increasing levels of solar penetration result in avoidance of energy from lower cost generation units."[45] While there might be environmental benefits from displacing efficient, low-cost natural gas units with PV resources, the long-run avoided cost benefits are fairly minimal.

Also, distributed resources may not be as efficient at reducing line losses as has been suggested. As the Xcel study explains, "Given the relatively low correlation between solar generation and feeder load across an entire calendar year, annual *avoided* distribution line losses are no greater than annual *average* distribution line losses."[46]

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[39] Ibid., p. 72
[40] Tom Tiernan. "Load forecasting is getting more difficult." *Megawatt Daily*, September 20, 2013.
[41] Ibid.
[42] Cristin Lyons, Stuart Pearman, and Paul Quinlan. *Distributed Resources and Utility Business Models – The Chronicle of a Death Foretold.* Scott Madden Management Consultants, 2013, p. 10.
[43] Xcel Energy Services. *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System.* 2013, p. ii.
[44] Ibid.
[45] Ibid., p. 5.
[46] Ibid., p. iii.

## Hawaii Solar Integration Study

The National Renewable Energy Laboratory (NREL) conducted a study of solar integration in Hawaii. Solar DG developed comparatively early in Hawaii, and so presented an opportunity for researchers to examine the effects of renewable generation on the grid. This study examined both utility-scale and DG-scale renewable resources on the grids of Maui and Oahu.

The NREL study found that power production from distributed solar installations were less variable than utility-scale installations because of their geographic diversity. For example, scattered cloud cover could disrupt power production at a few distributed generators at a time, while it could halt all generation at a utility-scale site. Conversely, high-scale penetration of distributed solar generation presents operational issues due to the inability of the utility to curtail power production.[47]

Variability in renewable generation impacts how other fuel sources are deployed. When renewable production is high, it may be necessary to ramp down fossil fuel plants, perhaps to minimum operating levels. At some locations in the study, fossil fuel plants operated in this manner over 90 percent of the time. The study did not examine the operation and maintenance expenses associated with operating baseload plants at minimum levels for such a long duration.[48]

Another effect of high renewable penetration is greater reliance on nonsynchronous generation. Conventional plants use a synchronous generator "that literally spins in synchronicity with the frequency of the power supply; the generator's rotation period is exactly equal to an integral number of alternating current cycles." This helps the grid to maintain operating parameters and controls voltage. Nonsynchronous generators such as wind and PV do not provide this kind of grid support, thus potentially destabilizing the grid.[49]

The rapid rise and fall of production in variable resources creates other risks. When PV generation drops off for five or more sustained minutes, it challenges the ability of conventional plants to compensate by ramping up production. A 30-60 minute sustained drop in production "consumes up-reserve resources and requires quick-start units."[50] While the conventional units responded during periods of sustained outages, there were times during when 20-60 MW of contingency reserves were used while renewable production ramped down. During one event, 128 MW of contingency reserves were tapped to compensate for the loss of renewable power. Considering that this took place on the island of Oahu's power grid, where there is a total of approximately 1,800 MW of firm power, this represented a significant portion of the island's electric generating capacity.

The opposite situation presents more of a challenge to the grid. If conventional units are already operating at a minimum level due to high renewable output, the output cannot be reduced further if there is a sudden increase in wind and solar generation output. This means conventional plants must use more down-reserves (reserves for periods when renewable output is high), with the

[47] Kevin Eber and David Corbus. *Hawaii Solar Integration Study: Executive Summary.* National Renewable Energy Laboratory, 2013, p. 2.
[48] Ibid., p. 10.
[49] Ibid., p. 11.
[50] Ibid.

result being that the down-reserves fall below minimum levels. During the study, there were more than 2,000 hours of down-reserve violations, which endangered grid reliability.[51]

Though in most cases the risks to the grid of blackouts or equipment damage due to DG are fairly minimal, there are costs associated with keeping these risks low. Utilities will have to make further capital investments to ensure that the grid continues to operate efficiently as more distributed resources are deployed. Utility customers must pay for these capital investments. Since owners of DERs may have electric bills approaching zero (depending on the rate and net metering regime that applies), the customers who create the need for these capital investments may be contributing little or nothing to the associated capital costs. Rate structures surrounding DG generally inhibit utilities from collecting the revenues necessary to maintain reliable operations in the face of increased DG penetration and variability in output, and therefore they must rely on traditional customers to pay for the costs associated with DG customers.

[51] Ibid.

## III. The Costs of Distributed Generation

Beyond operational and safety issues associated with DG the financial implications of increased DG penetration are also important. Utilities lose revenue as more customers choose self-generation. Moreover, it may be difficult through traditional rate design practices to recover the costs associated with DG programs from the DG customers. Both factors can lead to increased rates for the non-DG customers, financial losses to the utilities, or both.

The full scale of revenue loss can be seen in California, where there is a relatively high penetration of distributed PV installations. The three investor-owned utilities in California estimate they will have to make up $1.4 billion in lost revenues once the original caps on DG have been reached.[52]

As discussed above, proponents of DG argue that the benefits outweigh or at least mitigate the costs. A report produced by the National Regulatory Research Institute (NRRI) analyzed and summarized several studies attempting to estimate the monetary value of distributed resources. NRRI summarized the other studies' conclusions:

> [T]hat there is little, if any, subsidy to solar producers when solar electricity is valued at the customer's average retail price, which it is in many net metering programs. This is because solar PV production in many jurisdictions generally coincides with high-cost days and hours, thus displacing what would otherwise be above-average cost, marginal energy production, or purchases.[53]

If these studies are to be believed, net metering may actually under-compensate solar generators.

However, it should be recognized that varying circumstances affect costs and benefits associated with DG. For instance, the avoided energy cost benefit for utilities in states without a RPS are less than for utilities in states that have a RPS. Since PV distributed resources are not helping utilities in non-RPS states meet a requirement, this diminishes the value of these resources.[54]

Rate structures further complicate the cost/benefit analysis. As NRRI points out, most residential rates have only two components: a fixed monthly customer charge (often fairly minimal), and a variable energy charge. In the service territories of the vast majority of utilities throughout the country, a residential customer's energy bill is largely determined by the amount of energy consumed throughout the billing cycle, and the total bill rises and falls in sync with that customer's energy usage. Commercial and industrial customers, on the other hand, usually have a third component to their bill: a fixed demand charge per kilowatt that reflects the highest hourly demand of any billing period. These demand charges do not necessarily change when solar PV is installed.[55] Therefore fixed cost recovery may be less of a concern in the commercial sector than in the residential sector, even if overall revenue losses would be more substantial in the former category.

[52] Diane Cardwell, "Utilities Confront Fresh Threat: Do-It-Yourself Power," *New York Times*, July 26, 2013
[53] Tom Stanton. *State and Utility Solar Energy Programs: Recommended Approaches for Growing Markets.* Silver Spring, MD: National Regulatory Research Institute, 2013, p. 24.
[54] Ibid., p. 25.
[55] Ibid., pp. 25-26.

The NRRI report also notes that benefits of PV generation are reduced after a certain level of penetration. For example, minimal penetration leads to fairly low operations and maintenance (O&M) costs, but high levels of market penetration could lead to increased O&M costs due to the capital investments needed to manage more variable, two-way energy flows. These increased O&M costs would negate many of the system benefits provided by DG.[56] The value of avoided energy and capacity costs might also diminish after a certain level of market penetration.

## The Impacts of Increased DG Penetration

As discussed earlier, even generally optimistic projections show that DG penetration will be fairly small, especially when placed in the context of traditional generation resources. However, that does not mean distributed resources will constitute an insignificant portion of the electric market.

Navigant estimates that by 2018 worldwide revenues from PV distributed resources will reach $118 billion a year.[57] More significant from the American market perspective is that solar may be approaching the point of competitiveness with traditional grid power in many parts of the country. Parts of the Northeast could reach grid parity within three years and it is possible a majority of states will see solar PV rates that are equal to or less than retail electricity prices within the next decade.[58] This means it would be no more expensive in many parts of the country to generate your own power than to buy it from the electric utility.

Many businesses are seeing an opportunity to save money by installing solar panels. Wal-Mart plans to install solar PV on 1,000 of its retail stores (or approximately one-quarter of its U.S. locations) by 2020.[59] Other businesses, such as Verizon and MGM Resorts, have similar plans, though on a smaller scale. Even the partial loss of the load of these large customers would lead to a significant reduction in utility revenues.

### Customer Subsidization

Utilities are certainly not the only ones impacted by the growth of distributed generation resources. Utilities already are recovering lost revenues from DG customers by passing these costs to remaining retail utility customers. Returning again to the California utilities mentioned above, these three utilities estimate that if the costs associated with lost revenues were spread evenly among the 7.6 million traditional customers, each customer would experience an average annual increase of $185 in electricity costs.[60]

In essence, DG customers are subsidized by non-DG customers. As Ashley Brown and Louisa Lund pointed out in a recent article, generally speaking, DG customers tend to have higher incomes than other customers. "Thus, any additional cost or delta revenue loss attributable to DG that is passed on to the balance of customers has a high probability of being a wealth transfer

[56] Ibid., p. 28.
[57] Chris Martin, Mark Chediak, and Ken Wells. "Why the U.S. Power Grid's Days Are Numbered," *Business Week*, August 22, 2013, accessed at http://www.businessweek.com/articles/2013-08-22/homegrown-green-energy-is-making-power-utilities-irrelevant.
[58] Ibid.
[59] Ibid.
[60] "Utilities Confront Fresh Threat: Do-It-Yourself Power."

from the less affluent to the more affluent."[61] This socially regressive outcome is compounded by the institution of higher fixed charges (which utilities will have to implement to recover lost revenues), which are shared equally by all customers, Brown and Lund said. Low-income customers who consume comparatively less electricity than other customers will thus potentially face substantially higher electric bills, at least as a percentage of their current bills.

These are not the only potential unintended consequences of DG, according to Brown and Lund. When DG customers are paid or compensated for their excess generation – especially when the compensation is at the full retail rate –distribution costs are included in the amount, even though DG customers often do not help the utility save on distribution costs through their generation activities, and do not incur such distribution costs themselves. Since utilities will lose money on DG, they will try to recoup some of that money through higher fixed charges.[62] These higher fixed charges could hamper energy efficiency efforts. As Brown and Lund put it:

> The ironic result would be that less and less of the electricity bill is tied to actual usage, with the anti-green result that the rewards for energy efficiency, energy conservation, and distributed generation itself become smaller and smaller as more and more costs are shifted to the one part of the bill that everybody has to pay without regard to the level of consumption. In short, the fundamental environmental principle, "polluter pays," which in electric pricing means greater emphasis on the part of the bill that rises with consumption, will be violated in the name of promoting "green energy."[63]

As discussed below, not all state regulators may be amenable to raising fixed charges, though that leads to other potential problems.

### Community Solar and Solar Leasing

Community solar programs represent another challenge. Under these programs, customers are able to purchase shares of generation either from an apartment complex or other large, fixed PV installation. Community solar programs provide an opportunity for lower income customers and non-homeowners to gain access to distributed generation, but they also create new concerns for local distribution utilities.

Community solar programs can be designed a number of ways. One example can be found in San Diego, California, where solar power provides output equivalent to 100 percent of the power

[61] Ashley Brown and Louisa Lund. "Distributed Generation: How Green? How Efficient? How Well-Priced?" *Electricity Journal*, April 2013, p. 32. A California PUC study showed that customers who had installed DG systems since 1999 in the state had average household incomes of $91,210, compared to median household incomes in the IOU service territories of $54,283 and $67,821. Seventy-eight percent of net metered customers had incomes higher than the median California income, though this gap has been declining somewhat in recent years. See Ehren Seybert, *California Net Energy Metering (NEM) Draft Cost-Effectiveness Evaluation*, prepared by California Public Utilities Commission Energy Division, September 26, 2013, p. 110.
[62] Ibid., p. 30.
[63] Ibid., p. 31.

needed for the recently opened Solterra EcoLuxury apartment complex. A total of 338 kW of electricity is being furnished to 114 units in the complex.[64]

Colorado's community solar gardens program allows a higher cross-section of customers to own solar generation. These solar gardens are ground-mounted or solar installations from which individuals can purchase power. The Colorado Public Utilities Commission drafted rules governing the solar gardens, mandating that they cannot be more than 2 MW and must have at least 10 subscribers, each of whom must own at least a 1-kW share. Utilities must also purchase 6 MW of power from solar gardens by 2013, half of which must come from solar gardens smaller than 500 kW.[65] When Xcel Energy's program opened in 2012, it sold out in 30 minutes.[66]

These programs allow customers who either do not own their homes or who do not have the finances to pay directly for solar installations the means to own at least some distributed capacity. A 1 kW share in the Colorado program costs $3,700, so it still may be difficult for low-income customers to gain access to the Colorado program, though Cooper Credit Union does offer loans to cover the purchase costs.[67]

Electric customers have other means of accessing solar generation without paying up-front costs for installations. Companies like SolarCity will install solar panels on home rooftops without up-front cost to the customer; the customer leases the panels and pays for them on a monthly basis. As the company touts on its website, the payment remains fixed through the life of the lease. Therefore, customers may see significant savings if their electric rates increase during the lease period.[68]

Utilities with high electric rates are uniquely susceptible to developers such as SolarCity coming into their service territory, particularly if the monthly lease payment is much lower than the typical electric bill the customer is already paying. SolarCity has marketed aggressively in areas with high electric rates and is looking to expand its reach. Jimmy Chuang, a vice president for SolarCity, recently said "[t]he utility will not be able to stop us." He added, "The power will be decentralized . . . Going forward, at some point, 20 percent or 30 percent will be on-site generation, which means we will take some of the money away from utilities. So they have to kind of work with us." Chuang concluded, "This is the future. It doesn't matter if they like it or not."[69]

Even if these threats fall short, these comments demonstrate that certain participants in the distributed solar sector have a very aggressive attitude toward penetrating the utility market.

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[64] LPI Communications. *KYOCERA Solar Modules Power San Diego's First net-Zero Energy Apartments*. May 29, 2013, retrieved May 29, 2013 from ElectricityPolicy.com at http://www.electricenergyonline.com/?page=show_news&id=170504.

[65] Colorado Community Solar Gardens Act, available at http://www.solargardens.org/legislation-news-2/colorado-community-solar-gardens-act/.

[66] John Farrell, "Colorado's Community Solar Program Allots 9 MW in 30 Minutes," August 16, 2012, retrieved from IRLS.org. at http://www.ilsr.org/colorados-community-solar-program-allots-9-mw-30-minutes.

[67] Mark Jaffe. "Solar gardens give access to green energy to more Coloradans." *Denver Post*, June 23, 2013, retrieved at: http://www.denverpost.com/ci_23515682/solar-gardens-give-access-green-energy-more-coloradans

[68] http://www.solarcity.com/residential/solar-lease.aspx.

[69] Michael Copley. "SolarCity exec: Distributed generation is the future, whether utilities like it or not." *SNL Financial*, September 25, 2013.

SolarCity said it is willing to forgo profits in the immediate short-term to expand its presence throughout the country, a clearly risky business strategy.[70] The company hopes to benefit long-term by developing a large customer base through generous lease terms.

## Minimizing DG Risks

As DG becomes more widespread across the United States, utilities and utility advocates have begun developing proposals to address lost revenues. Rick Tempchin of the Edison Electric Institute (EEI) wrote two articles discussing the risks DG imposed on utilities. The loss of revenues, he said, "makes it more difficult for utilities to meet their fixed-cost obligations." Even when self-generating customers produce all or most of their power needs, the utility still incurs fixed costs in providing stand-by or back-up service. Furthermore, the utility under a net-metering arrangement often buys back power at the full retail rate, though this rate may be higher than the true value of the generation to the utility. As Tempchin put it:

> Paying credits at the full retail rate costs the utility money because that cost will be higher than the cost that the utility actually avoids by purchasing the DG power. For example, in centralized markets, a utility can buy all of its power needs at the wholesale rate. This rate will always be less than the full retail rate it would have to pay to buy the same power from a customer.[71]

It may be time to design rates that separate fixed and variable costs, Tempchin said. DG customers could pay some kind of non-bypassable surcharge to ensure that they are contributing covering their share of the utility's fixed costs. Tempchin also advocated a system that ties compensation for DG more closely to its value to the grid. For instance, in areas of high congestion, DG can provide cost savings to utilities in reduced capacity on the distribution network. Similarly, DG produced during peak demand periods has more value than off-peak generation.[72]

Fitch Ratings, one of the ratings companies that monitor utility finance issues, also has concerns about revenue stability and DG. It noted that net metering "can create pricing incentives to benefit one utility customer class over the majority of the customer base." That being the case, Fitch prefers a net-metering system to a feed-in tariff that provides cash payments to customers. "We consider credits for excess supply and caps on total net-metering production with higher fixed demand charges as essential components of rate design as net-metering programs grow," Fitch said.[73]

Fitch's approach would provide greater certainty. On the other hand, net metering has the disadvantage of compensating DG customers at the full retail rate and this rate may

[70] Avi Salzman. "Dark Clouds Over SolarCity." *Barrons Online*, August 31, 2013, accessed at: http://online.barrons.com/article/SB50001424052748704719204579025283044181654.html#articleTabs_article%3D1.

[71] Rick Tempchin. "Time to rethink metering rules: cost and fairness." *Intelligent Utility*, May 29, 2013. Accessed at http://www.intelligentutility.com/article/13/05/time-rethink-metering-rules-cost-and-fairness.

[72] Rick Tempchin, "Time to rethink metering rules: public policy." *Intelligent Utility*, June 3, 2013. Accessed at http://www.intelligentutility.com/article/13/06/time-rethink-metering-rules-public-policy.

[73] Fitch Ratings. *Solar Panels Cast Shadow on U.S. Utility Rate Design.* July 17, 2013. Accessed at http://www.fitchratings.com/gws/en/fitchwire/fitchwirearticle/Solar-Panels-Cast?pr_id=796776.

overcompensate DG customers. Both rate designs have benefits and drawbacks that must be considered fully before developing DG programs.

## Rate and Policy Alternatives

NREL produced a report that examined some potential rate design options for mitigating risks of feed-in tariffs. The first option, and one implemented by many jurisdictions that have FITs, is to place volume caps on the amount of program capacity eligible for FITs. In Hawaii, for example, the program cap was set at 5 percent of peak demand for each of the Hawaiian Electric Co. (HECO) affiliates. Hawaii also imposed program size caps to limit the size of individual projects.[74]

Volume caps provide a measure of predictability and cost control. But they might inhibit a jurisdiction's ability to foster clean technology development.[75] Volume caps also favor projects with faster development times. If early-developing projects have higher cost profiles, growth of DG might put upward pressure on prices.[76] Caps also engender "speculative queuing." Since projects are rewarded on a first-come, first-served basis, some projects with minimal potential to come on line may take up space in the queue, thus shutting out more viable projects.[77] Finally, caps increase uncertainties for project developers. If utilities do not award FIT treatment until a project reaches certain milestones, projects might be partially built before developers realize the cap has been reached.[78]

NREL also examined payment level adjustments, which are methods of keeping payments in line with market developments over time. There are several options for establishing payment level adjustments, all of which are aimed at adjusting rates over the life of a FIT contract. One option is to establish a pre-determined degression rate over the life of the contract, while another option is to peg the degression rates so they respond to market prices. A third option is a volumetric approach where rate level adjustments are tied to achievement of specified capacity milestones. A final approach is a system of bidding similar to what is done in Spain.[79]

Payment level adjustments offer some protection for ratepayers, as they reduce the potential for overpayments. This approach, unlike rate caps, might spur short-term development as investors see that payments are scheduled to go down over time.[80] But price adjustments could induce market volatility. It is also possible for these payments to deviate markedly from market realities, thus requiring some level of oversight to ensure that they do not differ significantly from market prices.[81] Additionally, if the rates exceed avoided costs, PURPA provisions would come into play, thus requiring FERC to set the rates.

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[74] Claire Kreycik, Toby D. Couture, and Karlynn S. Cory. *Innovative Feed-in Tariff Designs that Limit Policy Costs.* Golden, CO: National Renewable Energy Laboratory, 2011, p. 8.
[75] Ibid., p. 9.
[76] Ibid., p. 10.
[77] Ibid.
[78] Ibid., p. 11.
[79] Ibid., pp. 13-14.
[80] Ibid., pp. 22-23.
[81] Ibid, p. 23.

## The Utility Experience

With utilities growing more worried about the impact of DG, several have begun suggesting reforms to existing programs to alleviate some of the financial concerns associated with DG.

### Arizona Public Service

One of the most public controversies is taking place in Arizona, where Arizona Public Service (APS), an IOU, is proposing to amend its net metering program. In a July 12, 2013, filing with the Arizona Corporation Commission (ACC), APS made two policy proposals. Under the first policy option, existing net metering customers would pay a higher service charge based on the amount of electricity they use. This demand charge would range from $45 to $80 per month. A second option would establish a credit system for new DG customers. Under this system, distributed generators would be compensated for electricity sold to the grid at a rate set by the ACC, and this would appear as a credit on the customer's monthly bill.[82] The first proposal would reduce monthly savings for residential solar customers from 14-16 cents per kWh to 6-10 cents per kWh for the current 18,000 solar rooftop customers. The second proposal would reduce savings to about 4 cents per kWh per month.[83]

APS's proposals drew considerable criticism from both its DG customers and solar industry groups who believe these actions would stunt the growth of PV generation. APS defended the proposals, arguing that they are designed to create a fairer system in which DG customers would compensate the utility for their continued reliance on the grid:

> Even APS's customers who generate their own electricity with rooftop solar panels rely on the grid 24 hours a day: for power to supplement their solar supply when it does not meet all their needs; as a means to export electricity; and for backup power when panels fail or the sun does not shine.[84]

APS says that the total subsidization of rooftop solar customers amounts to approximately $18 million per year for APS customers. The utility also said the excess generation from solar rooftops does not save the utility money. Under the current system, rooftop generators are compensated at the full retail rate. If that power were not available, the utility would have purchased that electricity on the wholesale market at a lower cost.[85]

### Xcel Energy

Xcel Energy in Colorado is proposing to add a surcharge on all retail customer bills to cover the costs of net metering for new installations. To maintain rate neutrality, this surcharge would be cancelled out by a credit to the Electric Commodity Adjustment (ECA).[86]

The proposal is part of Xcel's plan to educate the public about the cost of DG and its subsidization effects. In its filing before the PUC, Xcel said:

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[82] Michael Copley. "APS's distributed solar proposals meant to create 'fair' system, utility says." *SNL: Electric Utility Report*, July 12, 2013.
[83] Michael Copley. "Demand charge under APS rooftop solar proposal would add up to $80 in monthly fees." *SNL: Electric Utility Report*, July 15, 2013.
[84] Michael Copley. "APS defends proposed regulatory changes with focus on value of rooftop solar." *SNL: Electric Utility Report*, July 22, 2013.
[85] Ibid.
[86] Jeff Stanfield. "Xcel Energy proposes surcharge to show costs of net metering for solar programs." *SNL: Electric Utility Report*, August 5, 2013.

> Our recommended plan also incorporates our efforts to start a dialogue about the need for and the equity of the incentives in the on-site solar program. In particular, we seek to transparently show the impact of the incentive net metering provides to customers that install PV systems, and to discuss the equity of that incentive. We seek to discuss the prospect that the net metering incentive either needs to be ramped down over time or that other rate design solutions must be explored to address the incentive net metering provides for future installations.[87]

Xcel does not propose any changes for its existing DG customers.

### Kansas City Power & Light

An IOU in Missouri, Kansas City Power & Light (KCP&L), wants to suspend solar rebates through the remainder of 2013. The current rebate, $2 per watt, was established under the state's renewable portfolio standard. The utility says the program is now at capacity. KCP&L siad it is not seeking to hurt the solar industry, but is hoping to "protect our customers who do not receive solar rebate payments from paying a subsidy that is no longer rationally related to the solar market."[88] More than 95 percent of solar installations are located in affluent zip codes, thus burdening low-income and small business customers to cover the rebates, the utility said.[89]

The Xcel and KCP&L examples highlight two of the growing concerns with DG, namely that non-DG customers are paying a disproportionate share to cover DG costs, and that these non-DG customers are generally less wealthy than the DG customers they are effectively subsidizing. DG supporters have disparaged these claims, and as discussed earlier, have argued that DG provides an overall monetary benefit in terms of system costs.

## State Actions Regarding DG Reform

### Idaho

Two states have recently rejected proposals to amend utility net metering programs. Idaho Power had proposed to increase the customer charge for residential net metering customers from $5 per month to $20.92, and from $5 to $22.49 for small business net metering customers. Idaho Power would have also established a load capacity charge of $1.48 per kW for residential customers and $1.37 for small business net metering customers. It would have also reduced the retail energy rates for net metering customers, while increasing the capacity limit for the program.[90]

The Idaho Public Utilities Commission denied this request, citing concerns over the chilling effect this could have on net metering. The commission expressed concerned that this proposal would encourage "rate gaming," where large customers install small solar systems to qualify for lower electric rates. The commission approved a proposal to switch to a credit system that allows

[87] Before the Public Utilities Commission of the State of Colorado, In the Matter of the Application of Public Service Company of Colorado for Approval of its 2014 Renewable Energy Standard Compliance Plan, Docket No. 13A-___E, July 24, 2013. Accessed at: http://www.snl.com/Cache/18477192.PDF?Y=&O=PDF&D=&FID=18477192&T=&OSID=9&IID=.

[88] Kelly Harrington-Andrejasich. "KCPL-GMO seeks suspension of solar rebate until 2014. *SNL: Electric Utility Report*, July 22, 2013.

[89] Ibid.

[90] Idaho Public Utilities Commission. "Most of Idaho net metering proposals denied." Case No. IPC-E-12-27, Order No. 32846, July 3, 2013.

net metering customers to receive a kilowatt-hour credit for excess generation instead of receiving a payment; however, the commission rejected Idaho Power's suggestion that the credits expire at the end of the December billing cycle. Instead, the credits would carry forward as long as the customer continues on a net metering program at the same site.[91]

### Louisiana

The Louisiana Public Service Commission (PSC) also vetoed a proposal to decrease payment rates to DG customers. State law requires utilities to purchase customer-generated energy at the full retail rate. Commissioner Clyde Halloway suggested basing compensation on the utility's avoided cost, but the PSC rejected his proposal on a 3-2 vote.[92]

### California

In California, legislation passed in September 2013 gave the CPUC authority to implement up to a $10 surcharge on all of the regulated IOUs' monthly bills for retail electric service, with a $5 surcharge for low-income customers. AB 327 also removes some limitations on and extends the deadline for mandatory time-of-use (TOU) rates. The bill paves the way for the removal of net metering volume caps. Net metering programs had been capped at 5 percent of a utility's aggregate customer peak demand. Under this bill, large electric utilities (over 100,000 customers) must establish a standard contract or tariff for net-metering customers and must make this contract available to eligible customer-generators by July 1, 2017, or sooner, if so ordered by the commission once the current cap is met. This effectively removes the net metering volume cap.[93]

### Minnesota

Minnesota implemented its solar energy standard in May 2013, mandating a 1.5 percent solar standard for the state's IOUs by 2020, meaning that 1.5 percent of their energy sales must be solar-powered. The standard also calls for utilities to develop a clean contract, feed-in tariff or standard offer for solar projects less than 1 MW in capacity. The standard increases the net metering cap from 40 kW to 1 MW for IOUs, creates a $5 million investment pool for small solar projects (under 20 kW), and authorizes community solar gardens.[94]

The CLEAN contract is one of the central pieces of this new standard and is modeled in part on Austin Energy's (Texas) Value of Solar program (discussed below). The value of solar has five components: energy, generation capacity, transmission and distribution value, transmission capacity, and environmental value. The price will vary annually, but distributed solar generators lock in their prices for 20 years when their projects come on line.[95] One caveat to the contract is that distributed solar producers are unable to profit from net generation. A distributed generator's

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[91] Ibid.

[92] Amanda H. Miller. "Louisiana PSC upholds net metering." Clean Energy Authority, July 1, 2013. Accessed at: http://www.cleanenergyauthority.com/solar-energy-news/louisaana-psc-upholds-net-metering-070113.

[93] Dana Hull. "Energy bill that could change electric rates heads to Gov. Jerry Brown." *San Jose Mercury News*, September 12, 2013. Accessed at http://www.mercurynews.com/business/ci_24081881/energy-bill-that-could-change-electric-rates-heads. A summary of the bill can be found here: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

[94] John Farrell. "Minnesota's New (Standard Offer) Solar Energy Standard." Grist.com, May 28, 2013. Accessed at Grist.com: http://grist.org/article/minnesotas-new-standard-offer-solar-energy-standard/.

[95] Ibid.

production is netted against its consumption, and if the former is greater than the latter, the bill is zeroed out.[96]

As these examples illustrate, even in states where utilities garner some concessions, state rulemaking bodies tend either to temper their requests or grant even greater concessions to solar rooftop customers in exchange for any concessions. Industry analysts will be keeping a close eye on the developments in Arizona, as they may provide influence how other states will treat attempts at reform.

These developments serve as a warning to public power utilities that changing DG pricing regimes may be difficult once they have been put in place, especially if the proposed changes are seen as being too onerous for solar PV customers. Public power utilities may have more independence in establishing rates and policies on DG.

[96] Ibid.

## IV. The Public Power Experience

Accelerated implementation of distributed energy resources poses a fundamental challenge to the IOUs, rural electric cooperatives and publicly owned electric utilities. Yet, publicly owned utilities are better positioned to deal with these challenges. The local, community-owned aspect of public power's business model affords these utilities the opportunity to develop strategies to mitigate adverse effects of DG penetration. However, because public power utilities are highly attuned to local community sentiment, they may encounter greater pressure to encourage further development of customer-owned generation, even if it adversely impacts utility operations and revenues in the long run.

This section details how certain publicly owned electric utilities have dealt with DG, the strategies they have put in place to integrate these resources in the most cost effective manner possible, and the political pressures to accelerate integration of distributed resources that some utilities have faced.

**Gainesville Regional Utilities (GRU)**

Gainesville Regional Utilities in Florida implemented its feed-in tariff – the first one implemented by any utility in the United States – in 2009. The GRU tariff was set at a high rate to encourage investment. The FIT for a rooftop solar system (less than 25 kW) was set at 32 cents per kWh, while the FIT for ground-mount systems (greater than 25 kW) was set at 26 cents per kWh. Participation was capped at 4 MW per year.

GRU's aggressive tariff reflected local considerations regarding renewable energy. Both the City Commission and GRU residents expressed support for increasing GRU's solar portfolio. It was hoped that greater solar implementation would promote both job growth and reduce carbon emissions.

GRU has modified the program in the intervening years. Initially, the FIT price was to be adjusted by an annual degression schedule, but now the price is determined before the beginning of each calendar year. GRU also implemented a size limit (previously there had been none) of 300 kW at each DG location. GRU also added administrative and capacity reservation fees as well as monthly customer charges in an effort to recoup more administrative costs.

As of the beginning of 2013, GRU's FIT was 21 cents per kWh for a small rooftop system. The price for a ground-mount system was 15 cents per kWh. GRU created a third class for larger rooftop systems (greater than 10 kW), and the 20-year fixed rate for systems installed in 2013 was 18 cents per kWh. The decline in the FIT over the past four years has coincided with a decline of about 30-40 percent in the overall installed price of solar PV systems over the same period.

Solar customers are also eligible for GRU's net metering program, which compensates excess generation at the full retail rate. The current policy does not prohibit customers from intentionally over-sizing systems in order to take advantage of this rate structure. GRU attempted to revise its net metering program and pay a rate that was more in line with avoided costs plus a modest premium; however, customer feedback prompted the utility to modify plans for restructuring the net metering program, instead aligning it with Florida's regulated net metering policy governing IOUs. GRU is now evaluating possible rate design options.

### Austin Energy

Like GRU, Austin Energy in Texas had distributed solar customers who sold excess energy, and thus profited from the utility's net metering program. In response to this, Austin Energy worked with Clean Power Research (CPR) to develop a "value of solar" rate, which is an attempt to set a more equitable rate for solar PV customers. The rate is based on an algorithm that incorporates six value components:

- Loss savings – reduction in line losses by producing power where it is generated.
- Energy savings – the offset of wholesale purchases.
- Generation capacity savings – benefits of added capacity that DG brings to the utility's resource portfolio.
- Fuel price hedge value – the value of having no fuel price uncertainty associated with solar PV.
- Transmission and distribution capacity savings – the value of reduced peak loading on the T&D system, postponing the need for capital investments.
- Environmental benefits – a recognition that the environmental footprint of solar PV is less than that of traditional fossil-fuel generation.[97]

These components are meant to reflect the value of solar energy to Austin Energy. As explained by those who designed the rate, it represents a "break-even value for a specific kind of distributed generation resource and a value at which the utility is economically neutral to, whether it supplies such a unit of energy or obtains it from the customer."[98]

The proponents tout several benefits:

- A fairer, more accurate rate.
- A reduction in the payback period for solar customers.
- Decoupling the credit from customer's consumption of energy encourages conservation and efficiency.
- Greater assurance that Austin Energy is charging for the full cost of serving customers.[99]

Under the program, the customer is billed for total consumption, then gets a credit from Austin Energy for PV production at the value-of-solar rate. If the customer's production exceeds consumption in a given month, then the customer receives a credit at the end of the monthly billing cycle that is rolled over to the next month. If the credit carries over to the end of the calendar year, the bill is zeroed out.

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[97] Karl R. Rabago, Leslie Libby, Tim Harvey, Benjamin L. Norris, and Thomas E. Hoff. *Designing Austin Energy's Solar Tariff Using a Distributive PV Value Calculation.* Austin, TX: Austin Energy, 2013, p. 2.
[98] Ibid.
[99] Ibid., p. 4.

## Los Angeles Department of Water and Power (LADWP)

The nation's largest public power utility has developed an incentive program to encourage the development of more renewable resources. The Los Angeles Business Council, policymakers and other stakeholders helped LADWP develop the feed-in tariff program in an effort to develop 150 MW of solar electricity in the city[100] The first phase of the FIT program was launched in January 2013 and is a 100-MW program that starts with a set price of 17 cents per kWh until the first 20 MW are subscribed, then decreases 1 cent per kWh for each additional 20 MW. LADWP plans to add 50 MW to complete the 150-MW FIT program, which "will be competitively priced through an RFP that is bundled with a utility-scale solar project."[101]

The city's ratepayer advocate suggested that LADWP is overpaying for the electricity, with the cost being born by non-solar customers. However, General Manager Ron Nichols said the rates are in line with market prices. "We've acknowledged we're paying a slightly higher incentive to make absolute certain we get major players here." Nichols said.[102] Currently, the program is aimed at large systems (150 kW to 3 MW), and likely will not include single-family homes, though there is a 4-MW carve-out for smaller systems (30-150 kW).[103]

## CPS Energy (San Antonio)

CPS Energy in San Antonio, Texas, offers one of the most robust rebate programs in the nation to customers who install solar PV systems. There are four customer tiers with different rate incentives. The first three tiers cover customers (schools, residential and commercial) who use installers who are registered with the CPS Energy solar rebate program and are local; the fourth tier is for customers who use non-local registered installers. [104]

The rebate program amounts and caps were reduced during the summer of 2013. The current rebate tiers are as follows:

- Tier 1: Schools - \$2 per AC watt for the first 25 kW AC in power capacity production and \$1.30 per AC watt for all remaining capacity output greater than 25 kW AC. This tier applies to commercial solar PV installations at accredited, nonprofit schools. The maximum rebate is \$80,000.

- Tier 2: Residential - \$1.60 per AC Watt up to \$25,000 or 50 percent cap, whichever is less. This rebate is available for residential solar PV installations. The maximum rebate is \$25,000.

- Tier 3: Commercial - \$1.60 per AC watt for the first 25 kW AC in power capacity production and \$1.30 per AC watt for all remaining capacity output greater than 25 kW AC. This rebate is available for commercial solar PV installations. The maximum rebate

[100] Catherine Green. "In L.A., getting paid to go green." *Los Angeles Times*, June 27, 2013. Accessed at: http://articles.latimes.com/2013/jun/27/business/la-fi-solar-buyback-20130627.
[101] "LADWP Takes Another Big Step to Create L.A.'s Clean Energy Future, Finalizes 150 MW Local Solar Program Plus 200 MW Utility Scale Solar." LADWP Press Release, May 21, 2013. Accessed at: http://www.ladwpnews.com/go/doc/1475/1780671/LADWP-Takes-Another-Big-Step-to-Create-L-A-s-Clean-Energy-Future.
[102] "In L.A., getting paid to go green."
[103] Ibid.
[104] DSIRE USA website, accessed at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=TX60F.

is $80,000, or 50 percent of total costs, whichever is less.

- Tier 4: $1.30 per AC watt for residential and commercial systems not installed by a local contractor, as defined in the tier 1 through 3 offerings. The maximum rebate is $25,000 for residential and $80,000 for commercial.

CPS Energy is addressing the challenge many utilities face with net metering and stranded infrastructure investment. Earlier this year, it proposed a credit per kilowatt-hour, known as SunCredit, rather than net metering. Instead of solar customers receiving the full retail rate, which is approximately 9.9 cents per kWh for residential customers, the SunCredit would be based on a market approach, taking into account the wholesale energy market price, transmission cost of service, etc. Working groups from both CPS Energy and local stakeholders are evaluating the proposal with the goal of reaching a consensus on the SunCredit rate.

### Seattle City Light

Net metering is available in Seattle City Light's service territory on a first come, first served basis, with a 10-MW volume cap. Customers receive a credit for each kilowatt-hour of excess generation, but Seattle City Light is prohibited by law from paying for generation, thus net bills cannot fall below zero.

The utility also has developed a community solar program that allows multiple customers to receive credit for the energy produced by a large solar array. Seattle City Light pays for the construction of a large solar array placed in a location of optimum solar exposure. Any utility customer can purchase solar units representing a share of the total output from the array. The customer receives a corresponding credit which is netted against the monthly electric bill. Additionally, customers receive the Washington State Production Incentive, which is double the rate paid to individual solar PV customers. Seattle's first community solar project was completed at Jefferson Park and has generated more than 24,000 kWh of electricity.[105]

### Santee Cooper (South Carolina Public Service Authority)

Santee Cooper's net billing program is a hybrid approach to DG, incorporating elements of both a feed-in tariff and net metering. The utility measures energy consumed and *separately* measures energy generated. Both the consumption charge and production credit are based on time of day pricing. Additionally, there is an on/off-peak demand charge designed to recover fixed costs.

A Santee Cooper analyst explained the rationale for this approach:

> Under the net billing rate design, customers only receive compensation for the energy delivered to our grid, and are not compensated for the fixed costs incurred by Santee Cooper. The underlying theory is that self-generating customers do not reduce Santee Cooper's obligation to serve their load, and we must still build generation, transmission, and distribution facilities to serve them; therefore fixed costs should still be appropriately allocated to and recovered from self-generating customers.

Like other utilities, Santee Cooper is seeking to keep rates as neutral as possible to avoid cross-class subsidization.

[105] "Community Solar Project at the Seattle Aquarium Now Enrolling." Accessed at: http://www.seattle.gov/light/solar/community.asp.

## Concord Light (Massachusetts)

Concord Light has a net metering tariff for solar PV customers who generate electricity in excess of their home consumption. The utility subtracts the excess production from the amount of electricity purchased by the customer from the utility, and the customer is then billed the net amount at the end of the period. If customers produce more generation than they purchase in a given month, they receive a credit equal to the price that Concord pays the New England Independent System Operator (NE-ISO) for energy on the spot market. The spot market price in 2012 was under 4 cents per kWh and was projected to be the same for 2013. This is substantially lower than the residential retail price, which ranges from approximately 14 to 17 cents per kWh.[106]

Concord Light recommends that its PV customers not attempt to size their solar systems to generate 100 percent of their electricity needs:

> If a system is sized to generate 100 percent of the customer's annual electricity needs, it is likely that the system will generate more than the customer needs during some months of the year. Sizing a system to generate somewhat less than 100 percent of the customer's annual electricity consumption minimizes the amount of excess electricity that is credited at the spot market price, which can be substantially lower than the applicable residential service rate. For this reason, a system sized to generate somewhat less than 100 percent of the customer's annual electricity needs will pay for itself more quickly than a system designed to produce 100 percent of the customer's annual electricity needs. Further, a system sized to generate somewhat less than 100 percent of the customer's annual electricity needs may allow the customer to take energy conservation actions to reduce home electricity consumption without increasing the likelihood that the system will generate more than the customer needs during some months of the year.[107]

Finally, Concord assesses PV customers a monthly distribution charge that increases incrementally as the system size increases. The monthly charge for the smallest unit (2-4 kW) is $3.60 per month. Twenty percent of each customer bill goes toward maintaining the distribution system and to cover the utility's operating costs. The distribution charge thus ensures that these costs are shared among all Concord customers, even those who generate some of their own electricity:

> Customers with solar PV systems continue to receive all of the services provided by the electricity distribution system in town and by Concord Light. Customers' adoption of solar does not reduce Concord Light's costs for maintaining local infrastructure and providing services. The customer acknowledges that the distribution charge is a condition of receiving net metering credits from Concord Light.[108]

## City of Wadsworth (Ohio)

Customers who self-generate and produce excess generation can receive a billing credit "equal to

[106] "Concord Light: Residential Solar PV Net Metering Policy Acknowledgement." Accessed at: http://www.concordma.gov/pages/ConcordMA_LightPlant/Netmeteringpolicyacknowledgement081613.pdf
[107] Ibid.
[108] Ibid.

the city's wholesale cost of energy, adjusted to include line losses." Net excess generation (NEG) credits carry over month-to-month, but zero out after the end of the calendar year.[109]

**Long Island Power Authority (New York)**

Long Island Power Authority offers net metering for both wind and solar DG. Under its Backyard Wind Initiative, LIPA pays a rebate that is the lesser of the first 16,000 kWh (at \$3.50/kWh) of use or 60 percent of total installed cost.[110] Under its Solar Pioneer Program, LIPA pays rebates to customers who buy their PV system. Rebates are calculated using the expected performance based buy-down (EPBB) method. EPBB "is an up-front incentive payment (rebate) for new grid-connected solar PV systems and inverters based on the expected output of the system compared to an ideal solar system installation."[111]

Both solar and wind generating customers are eligible for net metering. If a customer generates more than he consumes, he is billed for the daily service charge (line and meter costs) and excess generation in kilowatt-hours (credits) is placed in an energy bank. Customers can rely on the energy bank to pay for electricity in months when consumption exceeds generation.

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[109] City of Wadsworth Net Metering Rate Schedule Ordinance 2013. Accessed at: http://www.wadsworthcity.info/economic-development/25-pages/the-city/electric-department/759-net-metering.html/.

[110] Information retrieved from LIPA website at: http://www.lipower.org/residential/efficiency/renewables/wind-cost.html.

[111] Information retrieved from LIPA website at: http://www.lipower.org/residential/efficiency/renewables/solar-buy.html/

## Conclusion

Distributed generation presents both opportunities and risks for electric utilities. Relative to fossil fuel resources, there are environmental benefits to on-site generation produced by renewable resources such as solar and wind. Distributed generation may also help utilities avoid energy, capacity and ancillary service costs associated with conventional technologies. These resources may also help customers reduce electric bills and save money over the long term.

However, DG also presents a number of challenges. Under-recovery of costs, increased difficulties in operating the electric grid and safety issues are three of the foremost concerns related to the growth of distributed resources. Cross-class subsidization, particularly from lower-income customers to high-income customers, is another concern.

Publicly owned electric utilities may be uniquely situated to deal with DG. The independence of most public power utilities offers the opportunity to develop more equitable rates that do not stifle development of these resources nor unduly burden non-DG customers. However, publicly owned electric utilities may face pressure to encourage development of distributed resources even at the expense of revenue and operational stability. It is therefore imperative that publicly owned utilities fully understand the impact of distributed resources on their systems and explain those impacts to their boards, city councils and communities. DG regimes must be considered and designed carefully to ensure all customers benefit and provision of retail electric service is not adversely impacted.

Public outreach and communication is essential for all utilities when discussing and deciding DG-related issues. If a utility is preparing to change its rate structure to recover fixed costs, it needs to communicate reasons for doing so to avoid or at least minimize adverse customer reaction. Utilities may open themselves to the charge of being "anti-green" or "anti-consumer" if they try to implement significant changes without explaining why the changes are necessary.

Finally, utilities should prepare for a full range of potential outcomes from DG integration. In the event that DG is not disruptive to utility operations and revenue, it is better to have planned for the worst case than to be unprepared for the potential adverse impacts of wider DG implementation.

# Appendix: The German and Spanish Experiences

Germany and Spain experienced high growth in distributed capacity in the latter part of the previous decade. Though both countries put policies in place that promoted this growth, Spain's high growth came much more swiftly than anticipated, leading to a sudden slowdown in its promotion of the solar industry, which consequently resulted in economic turbulence. Though the German experience with distributed generation (DG) has been more positive, it has created some concerns about the long-term stability of the grid and has put upward pressure on prices. Though neither country is entirely similar to the United States, their early adaptation of solar PV provides lessons to us as the American market takes root.

## Germany

Germany was one of the first countries to develop a feed-in-tariff. The first German feed-in tariff (FIT) was established in 1990. The rates were too low to engender much market growth, but high rebates (up to 70 percent of system costs) and low-interest financing helped spur the development of 67 MW of capacity by the end of the decade.[112] After passage of the Renewable Energy Law (*Erneuerbare-Energien-Gesetz* or "EEG") in 2000, national FIT rates were more in line with the generation cost of PV systems and, by the end of 2003, 435 MW of PV capacity had been installed. Amendments to the renewable energy law in 2005 encouraged installation of additional capacity, bringing the total installed capacity to 5,979 MW by the end of 2008.[113]

Another round of significant capacity additions began in 2009 after more amendments to the EEG made FITs more favorable to developers. In 2009 alone, 3,806 MW of solar capacity were added to the grid. The new rate included a "corridor" or "flexible" digression system under which PV rates decreased based on the volume of PV capacity installed in the previous year. Since installations greatly exceeded projections, the rates decreased by 7.5 percent instead of the projected 6.5 percent.[114]

Growth was unprecedented in 2010, as 7.4 GW of new capacity was installed, much higher than the government projections of 6 GW. Due to this rapid increase in capacity, the government introduced two non-scheduled digressions, in addition to the already-scheduled price digression.[115]

Germany revised the EEG again in June 2012 to impose a subsidy cap once the cumulative capacity of solar generation reaches 52 GW (capacity was 27 GW in June 2012). The revision also eliminated all subsidies for installations larger than 10 MW. FITs were reduced by 25

[112] Mark Fulton and Nils Mellquist. *The German Feed-in Tariff for PV: Managing Volume Success with Price Response*. Deutsche Bank Group, May 23, 2011, p. 15.
[113] Ibid., p. 16.
[114] Ibid.
[115] Ibid., p. 17.

percent for the largest systems (40 kW to 1,000 kW), by 26.4 percent for systems between 10 and 40 kW, and by 20.4 percent for systems under 10 kW.[116]

Germany further reduced solar PV FITs at the beginning of 2013 as solar capacity continued to grow. The rates for small installations were reduced to just over 15 [Euro] cents per kWh, while the rates for the largest systems dropped to 10.4 cents per kWh. These changes applied only to systems installed in early 2013 and not to existing systems. These rates are still much lower than the overall retail rate for energy in Germany, which is approximately 27 cents per kWh.[117]

The German DG market has expanded to the point that there are now over 1.3 million households, farms and cooperatives generating power in Germany, providing 22 percent of the country's energy needs. This has had a tremendous impact on energy markets. For example, on a sunny day in June 2013, solar and wind supplied 60 percent of the nation's power needs, which actually led to negative wholesale prices in parts of the country.[118]

Though the rapid development of the solar industry in Germany is often touted as a success story, there have been negative repercussions. The average annual household subsidy for renewable generation is €144, or $181 (U.S.) and is anticipated to rise to over €200. This has exacerbated some class tensions. "Recipients of 'Hartz IV' welfare benefits for the long-term unemployed, for example, receive a fixed sum for electricity and can't afford energy-saving fridges or washing machines. At the other end of the scale, the owners of well-located houses install solar panels on their roofs and are paid for the privilege. Meanwhile, industrial companies that use a lot of electricity are being given more and more tax breaks."[119] One estimate calculates that those who are responsible for 18 percent of the consumption pay only 0.3 percent of the costs.

Germany's average retail electric prices are the highest in Europe and the average electric bill for a three-person household is €90 Euros, or twice the average bill in 2000. It is forecasted that prices could reach as much as 40 cents per kWh by 2020, or 40 percent more than today's prices. This has particularly put a strain on poorer customers and more than 300,000 households per year have their power shut off. This produces an even greater burden, as the reconnection fee to restore power can be as much as €100.[120]

The rapid expansion in the number of solar arrays, together with the variability in their generation, has also put a strain on the power grid. More land lines are needed, but grid expansion is years behind schedule. Solar and wind have priority on the grid, which means German industry is powered by renewable resources. Consequently, conventional resources are used primarily for backup. There are no financial incentives to promote construction of new

[116] Scott Burger. "Big Changes in German Solar Subsidy Policy Approved Today." *Greentechsolar*, June 29, 2012. Accessed at: http://www.greentechmedia.com/articles/read/Big-Changes-in-German-Solar-Subsidy-Policy-Approved-Today

[117] Renewables International. "German PV drops to 15 cents max." May 2, 2013. Accessed at http://www.renewablesinternational.net/german-pv-drops-to-15-cents-max/150/510/62457/.

[118] Matt McGrath. "German tariffs make green energy too expensive to store." *BBC News Online*, July 11, 2013.

[119] Stefan Schultz. "Germany Rethinks Path to Green Future." *Der Spiegel Online*, August 29, 2012.

[120] "Germany's Energy Poverty: How Electricity Became a Luxury Good." *Der Spiegel Online*, September 4, 2013. Accessed at: http://www.spiegel.de/international/germany/high-costs-and-errors-of-german-transition-to-renewable-energy-a-920288.html.

conventional resources.[121] In fact, at least 20 percent of the fleet of 90,000 MW of conventional power in Germany is at risk of closure and the loss of these resources could lead to blackouts.[122] The largest gas, electric and water utility in Germany, E.ON, is threatening to relocate to Turkey if its fossil-fuel and nuclear plants remain unprofitable.[123]

This expansion, and the regulation and legislation that have supported it, have rankled Germany's neighbors. The European Commission is threatening legal action over German energy subsidies. There has been an aggressive drive toward renewable energy, with a goal of 50 percent by 2030 and 80 percent by 2050. Costs for this transformation could exceed $1 trillion and will fall largely on German taxpayers. As Ambrose Evans-Pritchard writes, "The macro-economic effect of this distorted tax regime has been to compress household consumption while supporting companies, a mix that curbs imports and acts as a disguised form of protectionism. It is one of the many features of the German system that has led to accusations of mercantilism by other EU states."[124]

## Spain

The Spanish experience has been even more turbulent. A National Renewable Energy Laboratory report summarizes all that has happened. In 2005, Spain established a renewable energy target of 12.5 percent to be reached by 2010. The solar target was 400 MW. By 2006, installed solar capacity began to exceed the targets. A number of factors were at play. As the Spanish economy began declining, investors saw an opportunity for growth in the solar market, especially because of generous feed-in tariffs. Investors also perceived that a trigger mechanism in Spanish renewable energy legislation would weaken support for solar and so there was a rush to develop solar projects under the framework then in existence. This trigger mechanism was initiated when 85 percent of the 400-MW goal was reached. This initiated a one-year transition period during which developers had to bring their generation on line. Any generation not completed at the end of the one-year period would be paid much less than the FIT then in place. This led to a drastic boom in production between 2007 and 2008.[125]

The Spanish FIT established in 2007 guaranteed payments of up to 44 Euro cents per kWh for projects plugged into the grid by September 2008. Ground-based projects could receive a rate of return of up to 575 percent of average retail prices. The combination of high tariff rates and rapidly declining costs for PV systems "created an artificial market." There was no mechanism to reduce tariff rates if capacity targets were met. 350 MW of solar capacity had been installed in

[121] "Germany Rethinks Path to Green Future."
[122] The Global Warming Policy Foundation. "German Energy Companies Threaten Shutdown of Power Plants." July 16, 2013. Accessed at: http://www.thegwpf.org/german-energy-companies-threaten-shutdown-power-plants/
[123] William Pentland. "German Utility Revolts Against Renewable Energy, Threatens to Relocate in Turkey." *Forbes*, August 19, 2013. Sccessed at: http://www.forbes.com/sites/williampentland/2013/08/19/german-utility-revolts-against-renewable-energy-threatens-to-relocate-in-turkey/.
[124] Ambrose Evans-Pritchard. "Berlin facing EC bias claim over energy subsidies." *Daily Telegraph*, July 16, 2013.
[125] Claire Kreycik, Toby D. Couture, and Karlynn S. Cory. *Innovative Feed-in Tariff Designs that Limit Policy Costs*. Golden, CO: National Renewable Energy Laboratory, 2011, p. 5.

the country by the fall of 2007, just shy of the 400 MW that had been anticipated to come on line by 2010.[126]

A combination of soaring prices and taxpayer backlash ignited reforms. It was estimated that total payments to solar generators were $26.4 billion in 2008, during a time when the worldwide economy was in an enormous recession.[127]

In light of these developments, the Spanish Legislature aimed to scale back production, limited capacity additions to 500 MW for 2009 and 2010 and 400 MW for 2011 and 2012. The government also lowered the capacity limits for individual projects. In response to these changes, developers fled the Spanish market, leading to job losses in Spain. Investors and developers are now looking elsewhere.[128]

[126] Paul Voosen. "Spain's Solar Market Crash Offers a Cautionary Tale About Feed-in Tariffs." *New York Times*, August 18, 2009.
[127] Ibid.
[128] Kreycic, et al. p. 4.

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