Southwest Power Pool

Southwest Power Pool

FINANCE COMMITTEE MEETING

February 9, 2010

Dallas, Texas

• Summary of Action Items •

1. Approved minutes from December 7, 2009 meeting

• Schedule of Follow up Items •

1. Identify entities with poor meter data quality and offer to assist in improving the quality of meter data submission. Report to the committee the results of this effort.
2. Draft organizational charter to propose forming a Credit Working Group.
3. Draft organizational charter to propose forming a task force focused on meters within SPP.
4. Review settlement process for SPP administrative fee.
5. Formal review of forecast administrative fee for 2011 and 2012 in July 2010.
6. Distribute schedule detailing comparison of services across ISO/RTO
7. Update 2010 ISO/RTO budget information to include load served
8. Model administrative fee impact of including depreciation in rate recovery instead of scheduled principal payments on outstanding debt.
9. Review/determine benefits & costs of individual SPP services
10. Review of proposed changes to SPP depreciation schedules

Southwest Power Pool

FINANCE COMMITTEE MEETING

February 9, 2010

Dallas, Texas

• M I N U T E S •

Call to Order

Harry Skilton called the meeting to order at 8:30 am. The following members were in attendance:

Mr. Harry Skilton	Director
Mr. Larry Altenbaumer	Director
Mr. Kelly Harrison	Westar Energy
Mr. David Sartin	AEP
Ms. Trudy Harper	Tenaska
Mr. Gary Voigt	Arkansas Electric Cooperative
Mr. Tom Dunn	Southwest Power Pool

Southwest Power Pool staff participating: Nick Brown, Michael Desselle, Carl Monroe, and Bruce Rew
SPP members participating: Carol Shoemake (OG&E)

Minutes

The minutes from the December 7, 2009 meeting were reviewed. Kelly Harrison motioned to approve the minutes. The motion was seconded by David Sartin and approved by unanimous voice vote.

Administrative Fee Strategy

SPP staff provided and discussed the basic tenants of SPP's current administrative fee structure including; i) tariff language, ii) history, iii) peer group comparison, iv) administrative fee cost to tariff customers, v) value of SPP services, and vi) pro forma model of administrative fee levels from 2010 – 2016 using four scenarios (pay as you go, levelized, levelized stairs, and lowest).

The Committee participated in a discussion and exchange of ideas related to SPP's administrative fee covering both the administrative fee's impact in a utility's rate structure and the attractiveness of different structures for the administrative fee. Regarding structures, discussion ranged from whether it is better to have a rate that expects consistent scheduled adjustments, is stable for numerous years, builds working capital balances on SPP's balance sheet, etc. Additionally, discussion also occurred around whether SPP's current model of a single fee for all services was more or less desirable than an un-bundled fee where each service is priced separately and billed only to those customers who use the service. The Committee seemed to reach agreement that the current bundled rate met the needs of most SPP customers but SPP should attempt to provide greater clarity around its cost of service by service.

Ultimately, the Committee agreed the following were important aspects of the SPP administrative fee:

- Predictable – accurate SPP forecasts
- Smooth – doesn't move in a volatile manner
- Scheduled – visibility to changes rate are known in advance
- Diligent 3yr Forecast – forecast has strong correlation to future actual results

SPP staff was asked to provide additional information to the Committee on the following items:

- Comparison of services for ISO/RTO peers
- Load served by ISO/RTO peers

- Model administrative fee with recovery of depreciation
- Determine the benefits and costs of individual services
- Proposed changes to SPP's depreciation schedules

2010 Schedule 12 Fee

SPP staff reviewed the expected change to SPP's schedule 12 rate for 2010 (schedule 12 recovers costs associated with FERC's annual assessment of SPP). The 2010 rate will increase from slightly under 5 cents/MWh in 2009 up to slightly under 6.75 cents/MWh in 2010. The increase is driven by growth in FERC's assessment of SPP as well as true-up of under-recovery in 2008.

2010 Financing Strategy

SPP staff reviewed SPP's currently outstanding debt issues and payment obligations, the 2010 – 2012 capital expenditure project list and budget, and a proposed strategy to obtain funding for budgeted capital expenditures. SPP intends to engage a placement agent to market a private placement of up to $150MM in term debt incorporating various tranches and delayed funding alternatives to maximize SPP's benefits while minimizing risk and costs. SPP staff will return to the Committee in the near future seeking approval of specific issuances.

Other Issues

SPP staff verbally reported on SPP's compliance with its loan covenants at the end of 4Q'09. Also, staff updated the Committee on the status of negotiating an extension of the ICT agreement with Entergy.

Credit Discussion

At 2:00 pm the Committee convened a discussion of the recently issued Notice of Proposed Rulemaking by FERC covering specific credit issues related to ISO/RTO markets. The Committee welcomed the following individuals to participate in the discussion:

Tom Fritsche	Southwest Power Pool
Phil McCraw	Southwest Power Pool
Mark Soulliere	Tenaska
Mark Holler	Tenaska
Terri Wendlandt	Westar
Chandima Kodituwakku	AEP

SPP staff provided a brief summary of each specific component of the NOPR and summarized the initial direction from the membership. In general, SPP and its membership are supportive of the intent of FERC related to strengthening the credit requirements for participation in regional energy markets. SPP will continue to work with the membership to draft a response to the rulemaking which is specific to SPP and its members' interests. SPP will also participate in a joint filing of its ISO/RTO peer group responding to the proposed rulemaking.

Future Meetings

The next scheduled meeting of the SPP Finance Committee will be held on April 1, 2010 from 8:30 am to 2 pm at the Hyatt Regency DFW Airport Hotel in Dallas, TX. The primary topic for this meeting will be review of SPP's 2009 financial audit report and determination of 2010 benefit plan funding.

An interim teleconference meeting of the SPP Finance Committee will be held at a to-be-determined date and time in advance of the scheduled April 1 meeting. SPP will discuss and seek approval of its specific financing program at this time as well as discussing proposed changes to its depreciation policy and response to the FERC NOPR on credit requirements.

<u>Adjourn</u>

There being no further business, Harry Skilton adjourned the meeting at 4:15 pm.

Respectfully Submitted,

Thomas P. Dunn
Secretary

Southwest Power Pool, Inc.
FINANCE COMMITTEE MEETING
February 9, 2010

Dallas-Fort Worth Airport – Hyatt Regency Hotel

• AGENDA •

8:30 am – 2:00 pm

1. Old Business – Approval of Minutes.. Harry Skilton
2. New Business – Administrative Fee Strategy .... Tom Dunn
    a. Background
    b. Preferences and Priorities
    c. Tactics to Achieve Desired Strategy
3. New Business – 2010 Schedule 12 Fee (handout at meeting) .... Tom Dunn
4. Old Business – 2010 Financing Strategy .... Tom Dunn

Credit Discussion 2pm – 5pm

5. New Business – Credit .... Tom Dunn
    a. FERC NOPR on Credit
    b. Credit Impacts w/ Future Markets
6. Future Meetings .... All

Southwest Power Pool

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FINANCE COMMITTEE MEETING

December 7, 2009

Dallas, Texas

• Summary of Action Items •

1. Approved minutes from October 14, 2009 meeting

• Schedule of Follow up Items •

1. Identify entities with poor meter data quality and offer to assist in improving the quality of meter data submission. Report to the committee the results of this effort.
2. Draft organizational charter to propose forming a Credit Working Group.
3. Draft organizational charter to propose forming a task force focused on meters within SPP.
4. Review of 2010 – 2012 capital expenditure budget at February 9, 2010 meeting.
5. Review settlement process for SPP administrative fee.
6. Formal review of forecast administrative fee for 2011 and 2012 in July 2010.
7. Confirm feasibility and identify impacts of lengthening amortization of larger software applications from 3 years up to 7 or 10 years.

Southwest Power Pool

FINANCE COMMITTEE MEETING

December 7, 2009

Dallas, Texas

• M I N U T E S •

Call to Order

Harry Skilton called the meeting to order at 2:00 pm. The following members were in attendance:

Mr. Harry Skilton	Director
Mr. Larry Altenbaumer	Director
Mr. Kelly Harrison	Westar Energy
Mr. David Sartin	AEP
Ms. Trudy Harper	Tenaska
Mr. Tom Dunn	Southwest Power Pool

Southwest Power Pool staff participating: Nick Brown, Carl Monroe, Lanny Nickell, and Lauren Krigbaum.
SPP members participating: Carol Shoemake (OG&E)
Board of Director member participating: Jim Eckelberger
Others in attendance: Keith Conine, BKD; Tim Cherry and Sean Berry, PWC

Minutes

The minutes from the October 14, 2009 meeting were reviewed. Kelly Harrison motioned to approve the minutes. The motion was seconded by Larry Altenbaumer and approved by unanimous voice vote.

2009 Financial Audit

Keith Conine of BKD discussed the audit schedule and plan for the audit of SPP's 2009 financial reports. Additionally, Mr. Conine highlighted several recent accounting pronouncements which may impact SPP's financial statements. The Committee dismissed SPP staff and held a brief executive session with Mr. Conine.

2008/09 SAS70 Audit Report

Representatives from PWC reported to the Committee on the results of the SAS70 audit for the period November 1, 2008 through October 31, 2009. SPP's control environment satisfied the audit criteria for all controls with the exception of one business process control and 1 IT general computer control, both of which were noted as qualifications. Additionally, a physical security control was noted as an exception but was not qualified due to other compensating controls. SPP management responded with actions taken to address the noted control qualifications in the future. Additionally, SPP management reviewed its actions taken during 2009 to address control issues.

Lending Agreement Compliance

SPP management formally advised the Committee of a violation of a financial covenant contained in two of the Company's lending agreements. The violation occurred at the end of the third quarter 2009 reporting period. Further, SPP management reviewed actions taken by the Company following knowledge of the violation and its expectation of receiving waivers of compliance from each of the affected lenders. Additionally, going forward SPP will report to the Committee measurement of the financial covenant for the most recent reporting period as well as a forecast of the covenant levels into future reporting periods.

Settlement Timelines

The Committee reviewed the process for the timely submission of settlement meter data and then settling transactions in SPP's EIS market. The Committee requested SPP staff to determine the appropriate representatives to fill a proposed task force, which will report to the Finance Committee, organized to identify and implement enhancements to meters and their timely submission throughout the SPP footprint. A main objective to improving the timeliness and accuracy of metering in SPP that currently impact SPP's credit exposure in settlements and to ensure any needed additional metering infrastructure is in place in advance of the implementation of SPP's future markets.

Credit Processes for Future Markets

The Committee reviewed SPP's internal actions to date in preparation for SPP's future markets. The Committee requested SPP staff consider proposing forming a Credit Working Group which would serve as a permanent stakeholder group engaged to constantly oversee the formation, implementation and monitoring of credit policy for the Company.

SAS70 Request For Proposals

SPP management advised the Committee it will utilize an RFP process prior to engaging an audit firm to perform a SAS70 audit of SPP's controls for the November 1, 2010 through October 31 ,2011 period.

Future Meetings

The next scheduled meeting of the SPP Finance Committee will be held on February 9, 2010 from 8am to 2pm at the DFW – Hyatt hotel in Dallas, TX.

Adjourn

There being no further business, Harry Skilton adjourned the meeting at 6:15 pm.

Respectfully Submitted,

Thomas P. Dunn
Secretary

SPP Southwest Power Pool

Helping our members work together to keep the lights on…

today & in the future

SPP Administrative Fee Strategy

Background

Schedule 1A of SPP Tariff

For each calendar year, the Transmission Provider shall establish a rate for this administrative charge by dividing projected expenses based on its budget for the calendar year by the projected billing units for the calendar year. The Transmission Provider shall reconcile actuals to budget figures and shall adjust charges for the following calendar year to reflect over or under recoveries of its costs for the prior year.

Schedule 1A of SPP Tariff

Tariff currently provides for:

- 100% recovery of costs
- True-up of prior year over/under recovery
- Annual rate setting

Tariff currently does not provide for:

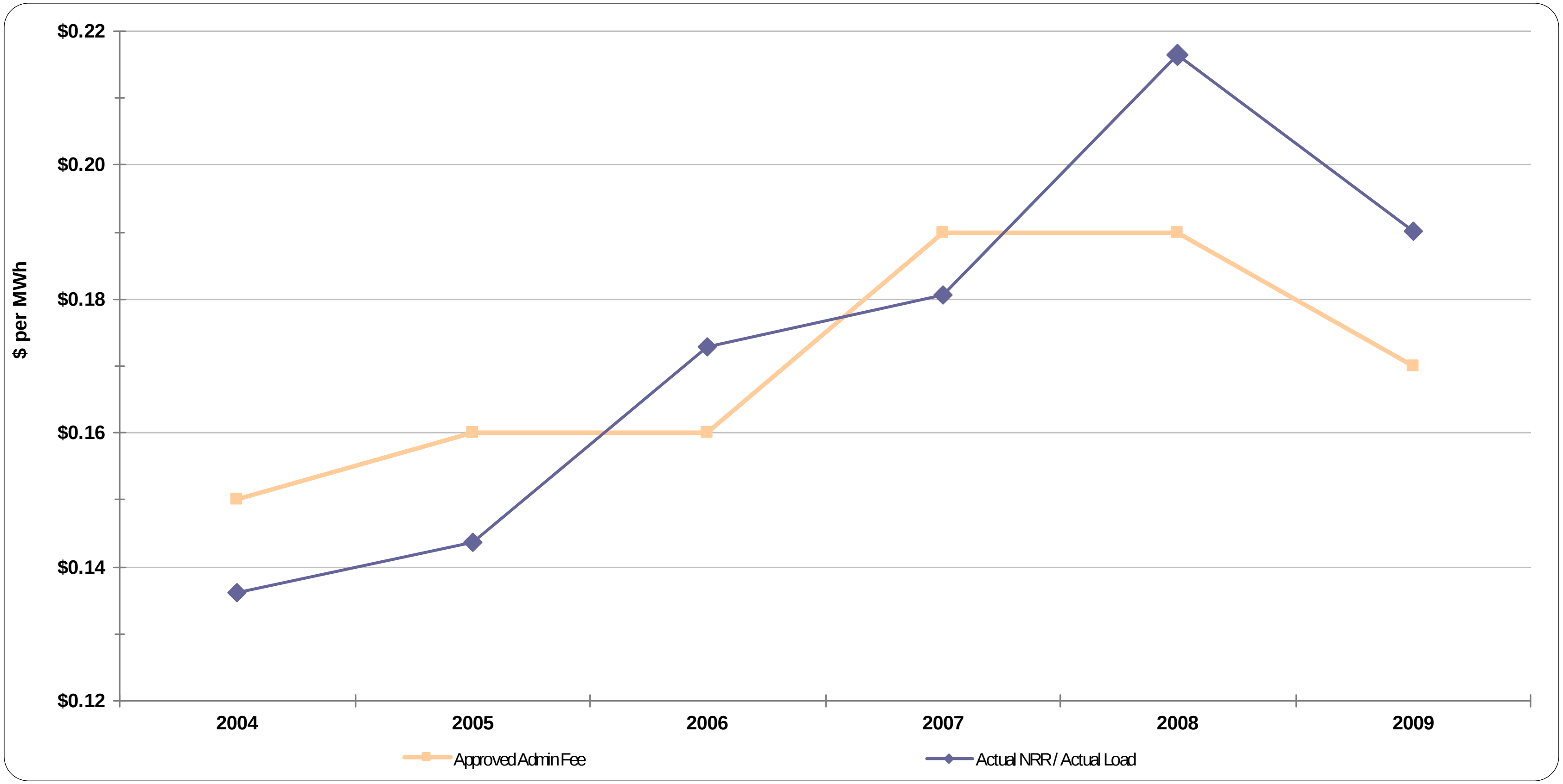
- Admin fee stability across years
- Establishing rate to collect more than current year budget costs
- Recovery of costs above 22.5 cents/MWh

Schedule 1A of SPP Tariff

Formula For Calculation:

Operating Expense	
Plus:	**Interest Expense**
	Scheduled Principal Payments
Less:	**Depreciation**
	Other Revenues (ICT, NERC, Sch 12)
Equals:	**Net Revenue Requiremend**
Divided:	**Estimated Load (MWhs)**
Equals:	**Rate +/- true-up**

Historical Admin Fee and Costs



SPP Costs Compared To ISO/RTO

2010 ISO/RTO Budget Comparison

($million, except rate information)

	CAISO	MISO	ISO-NE	NYISO	ERCOT	SPP
Operating Expenses	$ 162.7	$ 181.5	$ 108.9	$ 146.0	$ 100.6	**$ 107.3**
Debt Service/Depreciation	$ 61.0	$ 91.4	$ 26.4		$ 31.4	**$ 12.7**
Other Expenditures	$ 15.0 [1]				$ 18.5 [1]	
Capital Expenditures	$ 31.0 [2]	$ 52.8	$ 28.0		$ 46.3	**$ 73.3**
Forecast Load (GWh)	246.0	949.1	131.3	167.3	319.4	**333.5**
Rate	**$ 0.793**	**$ 0.265**	**$ 1.050**	**$ 0.898**	**$ 0.449**	**$ 0.205**

[1] CAISO and ERCOT fund some portion of capital expenditures with through their rates

[2] Capital expenditures excludes $160 million new facility

SPP Cost Impact To Members

SPP Admin Fee Paid By Representative Customers in 2008

	IOU	IOU	Muni	Gov't Agency	Coop
SPP Admin Fee Paid ($000)	$ 6,428	$ 1,768	$ 738	$ 862	$ 1,142
% of Revenues	0.35%	0.34%	0.33%	0.57%	0.17%
% of Operating Expenses	0.41%	0.40%	0.38%	0.64%	0.17%
% of O&M-Transmission			3.05%	8.12%	2.36%

Impact of 25% Increase in SPP Admin Fee

	IOU	IOU	Muni	Gov't Agency	Coop
% of Revenues	0.44%	0.43%	0.42%	0.71%	0.21%
% of Operating Expenses	0.52%	0.49%	0.48%	0.80%	0.22%
% of O&M-Transmission			3.81%	10.15%	2.96%

Value of SPP Services

- **Services where value can be estimated:**
  - **EIS Market – regional benefit of $100MM/year**
  - **Total Schedule 1A costs well below benefit for each year of EIS operation**
- **Services which are difficult to value:**
  - **Regional reliability coordination**
  - **One stop shopping for transmission service**
  - **Region-wide transmission planning**

Value of SPP Services

- **Services to be implemented / developed**
  - **Future Markets – expected net regional benefits of $100MM/year**
  - **ITP – construction of transmission w/ certainty of recovery through accepted cost allocation methodology**
  - **Consolidated Balancing Areas – centralized service resulting in operating efficiencies and cost efficiencies**

Projected SPP Admin Fee 2010 - 2016

	Projected Admin Fee "Pay As You Go" ($Millions)						
	2010	2011	2012	2013	2014	2015	2016
Assessment / Tariff Fees	$ 65.0	$ 94.3	$ 115.1	$ 124.0	$ 137.9	$ 137.3	$ 141.2
Other Revenue	43.3	39.2	39.7	40.7	41.9	43.1	44.3
Total Revenue	**$ 108.3**	**$ 133.6**	**$ 154.8**	**$ 164.7**	**$ 179.7**	**$ 180.3**	**$ 185.5**
Operating Expenses	$ 124.1	$ 136.3	$ 144.3	$ 151.0	$ 160.0	$ 166.5	$ 175.4
Other Income/(Expense)	3.6	2.1	(5.5)	(5.3)	(4.2)	(3.1)	(2.1)
Net Income	**$ (12.2)**	**$ (0.6)**	**$ 5.0**	**$ 8.4**	**$ 15.5**	**$ 10.8**	**$ 8.0**
Assessment & Tariff / MWh	**$ 0.209**	**$ 0.279**	**$ 0.336**	**$ 0.355**	**$ 0.387**	**$ 0.377**	**$ 0.381**
Fixed Charge Coverage	**1.794**	**3.188**	**2.398**	**2.863**	**3.721**	**3.504**	**3.609**
Debt Service / MWh	**$ 0.040**	**$ 0.061**	**$ 0.100**	**$ 0.106**	**$ 0.124**	**$ 0.103**	**$ 0.094**

- **Debt for Future Markets: 14 year maturity w/ first 4 years int only**
- **Debt for SPP campus: 32 year maturity w/ first 2 years int only**
- **Other financing issued w/ 5 year maturity**

Projected SPP Admin Fee 2010 - 2016

	Projected Admin Fee "Levelized" ($Millions)						
	2010	2011	2012	2013	2014	2015	2016
Assessment / Tariff Fees	$ 65.0	119.5	121.1	123.5	126.0	128.5	131.1
Other Revenue	43.3	39.2	39.7	40.7	41.9	43.1	44.3
Total Revenue	**$ 108.3**	**$ 158.7**	**$ 160.8**	**$ 164.3**	**$ 167.9**	**$ 171.6**	**$ 175.4**
Operating Expenses	$ 124.1	$ 136.3	$ 144.3	$ 151.0	$ 160.0	$ 166.5	$ 175.4
Other Income/(Expense)	3.6	2.1	(5.5)	(5.3)	(4.2)	(3.1)	(2.1)
Net Income	**$ (12.2)**	**$ 24.5**	**$ 11.0**	**$ 8.0**	**$ 3.7**	**$ 2.0**	**$ (2.0)**
Assessment & Tariff / MWh	**$ 0.209**	**0.353**	**0.353**	**0.353**	**0.353**	**0.353**	**0.353**
Fixed Charge Coverage	**1.794**	**6.691**	**2.788**	**2.830**	**2.721**	**2.688**	**2.571**
Excess Cash / Year	**(4.6)**	**25.1**	**6.0**	**(0.4)**	**(11.9)**	**(8.7)**	**(10.1)**
Cummulative Cash Balances	(4.6)	20.5	26.5	26.0	14.2	5.4	(4.6)

- **Requires changes to schedule 1A of SPP tariff**
- **Results in accumulated excess cash exceeding $26 in 2012**

Projected SPP Admin Fee 2010 - 2016

	Projected Admin Fee "Levelized Stairs" ($Millions)						
	2010	2011	2012	2013	2014	2015	2016
Assessment / Tariff Fees	$ 65.0	109.4	110.9	113.1	136.0	138.7	141.5
Other Revenue	43.3	39.2	39.7	40.7	41.9	43.1	44.3
Total Revenue	**$ 108.3**	**$ 148.6**	**$ 150.6**	**$ 153.9**	**$ 177.9**	**$ 181.8**	**$ 185.9**
Operating Expenses	$ 124.1	$ 136.3	$ 144.3	$ 151.0	$ 160.0	$ 166.5	$ 175.4
Other Income/(Expense)	3.6	2.1	(5.5)	(5.3)	(4.2)	(3.1)	(2.1)
Net Income	**$ (12.2)**	**$ 14.5**	**$ 0.8**	**$ (2.4)**	**$ 13.7**	**$ 12.3**	**$ 8.4**
Assessment & Tariff / MWh	**$ 0.209**	**0.324**	**0.324**	**0.324**	**0.381**	**0.381**	**0.381**
Fixed Charge Coverage	**1.794**	**5.288**	**2.122**	**2.025**	**3.565**	**3.643**	**3.646**
Excess Cash / Year	**(4.6)**	**7.3**	**(6.7)**	**(9.9)**	**6.2**	**4.7**	**0.9**
Cummulative Cash Balances	(4.6)	2.7	(4.0)	(14.0)	(7.8)	(3.1)	(2.2)

- **Requires changes to schedule 1A of SPP tariff**
- **Results in cash shortfall of $14 in 2013**

Projected SPP Admin Fee 2010 - 2016

	Projected Admin Fee "Low Rate" ($Millions)						
	2010	2011	2012	2013	2014	2015	2016
Assessment / Tariff Fees	$ 65.0	84.5	85.7	87.4	107.0	109.1	111.3
Other Revenue	43.3	39.2	39.7	40.7	41.9	43.1	44.3
Total Revenue	**$ 108.3**	**$ 123.7**	**$ 125.3**	**$ 128.1**	**$ 148.9**	**$ 152.2**	**$ 155.6**
Operating Expenses	$ 124.1	$ 136.3	$ 144.3	$ 151.0	$ 160.0	$ 166.5	$ 175.4
Other Income/(Expense)	3.6	2.1	(5.5)	(5.3)	(4.2)	(3.1)	(2.1)
Net Income	**$ (12.2)**	**$ (10.4)**	**$ (24.4)**	**$ (28.2)**	**$ (15.4)**	**$ (17.4)**	**$ (21.8)**
Assessment & Tariff / MWh	**$ 0.209**	**0.250**	**0.250**	**0.250**	**0.300**	**0.300**	**0.300**
Fixed Charge Coverage	**1.794**	**1.816**	**0.474**	**0.033**	**1.118**	**0.873**	**0.530**
Required Budget Reductions		**(9.8)**	**(29.5)**	**(36.6)**	**(30.9)**	**(28.1)**	**(29.9)**
Major Incremental Expenses Above 2010 Levels							
Principal Payments (New)		6.5	12.2	14.9	23.1	17.6	16.1
Incremental Staffing		10.0	15.2	18.9	22.8	26.9	31.2

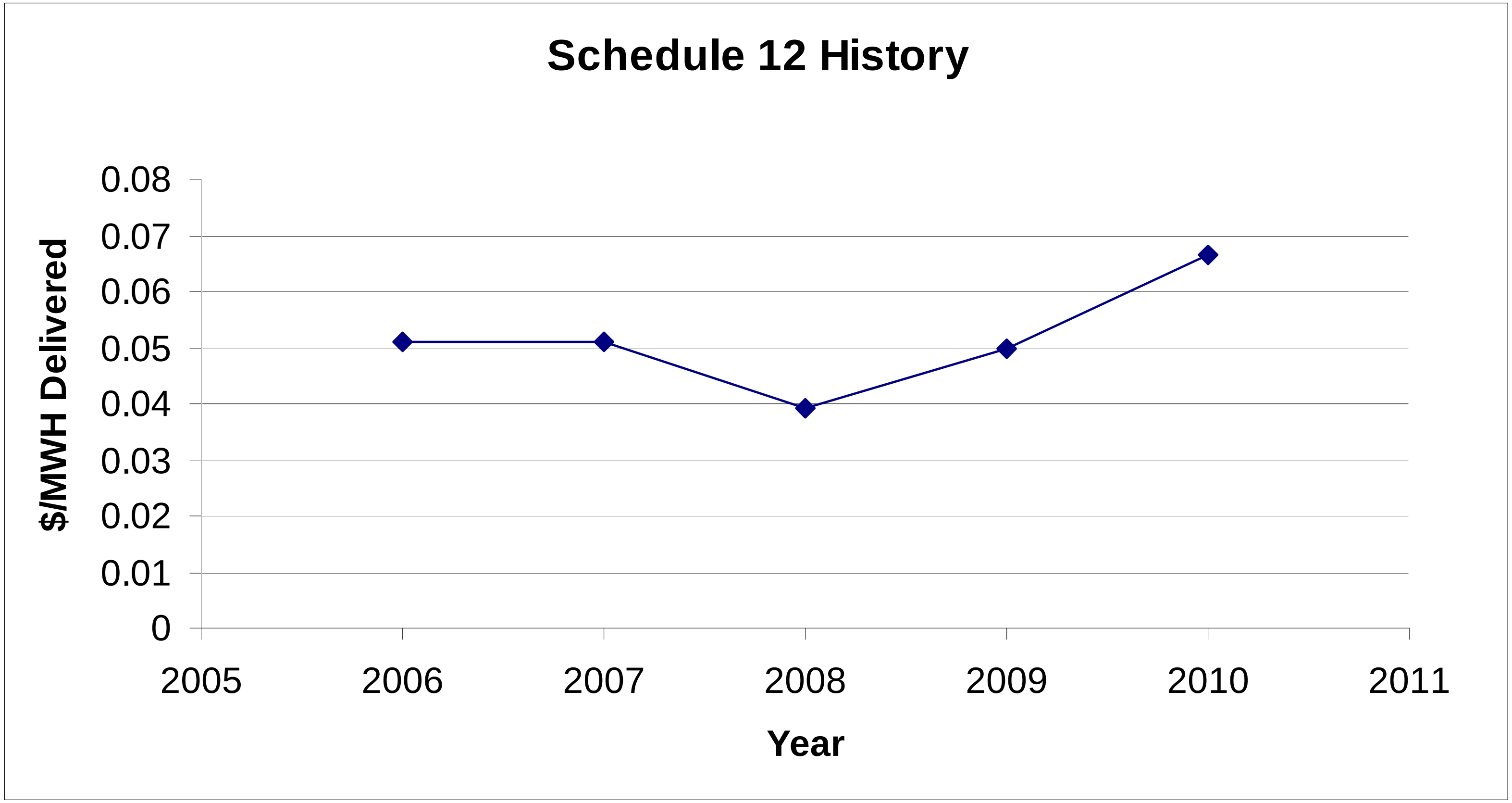
- **Requires significant reductions to forecast expenses**
- **Likely results in delay or elimination of strategic projects**

Discussion

- **What are our preferences?**
- **What are our limits of acceptability?**
- **What does it take to get there?**

Schedule 12

Historical Schedule 12 Rates



Financing Strategy

Existing Obligations

Outstanding Balance ($ Millions)	2010	2011	2012	2013	2014	2015	2016
2011 Sr. Notes	5.0						
2014 Sr. Notes	21.0	16.0	11.0	5.5			
2016 Sr. Notes	30.0	27.0	21.0	15.0	9.0	3.0	
Maumelle Mtg	4.4	4.2	4.0	3.8	3.5	3.3	3.1
	60.4	47.2	36.0	24.3	12.5	6.3	3.1

Scheduled Principal Payments ($ Millions)

Existing Issues	2010	2011	2012	2013	2014	2015	2016
2011 Sr. Notes	5.0	5.0					
2014 Sr. Notes	4.0	5.0	5.0	5.5	5.5		
2016 Sr. Notes	-	3.0	6.0	6.0	6.0	6.0	3.0
Maumelle Mtg	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	9.2	13.2	11.2	11.7	11.7	6.2	3.2

Ref #	Project	Responsible Director	Cap Ex 2010	Cap Ex 2011	Cap Ex 2012	Total
1	0120-SPP Budgeting & Forecasting System	D. Branch	$40	$0	$0	$40
2	0100-Vehicle for Transporting Equipment	T. Dunn	$34	$0	$3	$37
	Accounting Initiative Totals		$74	$0	$3	$77
3	0430-Under Frequency Load Shedding (UFLS) Study	B. Rew	$80	$0	$0	$80
4	0430-Under Voltage Load Shedding (UVLS) Study	B. Rew	$80	$0	$0	$80
5	0420-2009 GIS & Project Tracking Solutions	B. Rew	$0	$0	$0	$0
6	0430-SPP Annual Stability Analysis Tool	B. Rew	$80	$0	$0	$80
7	0860-0430 Aggregate Study Screening	B. Rew	$750	$0	$0	$750
8	0738-0430 Consulting Support for ITP Engineering	B. Rew	$100	$0	$0	$100
9	0554-0430 Consulting Support for Engineering Functions	B. Rew	$150	$0	$0	$150
	Engineering Initiatives Totals		$1,240	$0	$0	$1,240
10	0500-High Availability	B. Sugg	$4,170	$500	$500	$5,170
11	0890-Centralized Balancing Authority Services	L. Nickell	$350	$1,350	$50	$1,750
12	0710-Future Markets & CBA/Future Markets Training	Dillon/Nickell	$21,359	$20,666	$6,904	$48,929
	Future Market Inititives Totals		$25,879	$22,516	$7,454	$55,849
13	0575-2010 IT Foundation - Office Hardware and Software	B. Sugg	$2,105	$1,207	$1,158	$4,471
14	0570-2010 IT Server Refresh and Virtualzation	B. Sugg	$2,399	$872	$872	$4,143
15	0585-2010 IT Foundation - Network/Telecom/Security	B. Sugg	$561	$408	$903	$1,872
16	0585-2010 IT Network/Telecom/Security Refresh	B. Sugg	$357	$640	$1,035	$2,032
17	0585-2010 CIP Project	B. Sugg	$145	$85	$85	$315
18	0570-Active Directory Administration	B. Sugg	$536	$0	$0	$536
19	0570-Automated Script-Authentication Utility & Implement	B. Sugg	$477	$0	$0	$477
20	0530-IT R&D Environment	B. Sugg	$11	$0	$0	$11
21	0580-2010 IT Environmental Operations	B. Sugg	$205	$0	$0	$205
22	0500-Increased Generator Capacity for Maumelle	B. Sugg	$0	$4,500	$0	$4,500
23	EMS FTP Utility to Windows Service / Change to Update Legacy Applications to comply with Password Policy/SDA File Parser to Windows Service	B. Sugg	$0	$437	$0	$437
	IT Foundation / IT Operations Initiatives Totals		$6,796	$8,149	$4,053	$18,999
24	0700-BI Data Available to Internet Users	R. Dillon	$0	$0	$0	$0
25	0700-Data Dictionary	R. Dillon	$18	$0	$0	$18
	Market Department Initiatives Totals		$18	$0	$0	$18
26	0100-SPP Facilities Development Plan	T. Dunn	$32,950	$27,504	$1,743	$62,197
26.1	0100-Interest Expense Capitalization	T. Dunn	$2,096	$3,246	$3,420	$8,761
27	0100- SPP Facilities Furnishings - New Data / OPS	M. See	$0	$3,520	$0	$3,520
28	0500-New Facility Hardware for the New Data Center	B. Sugg	$0	$4,000	$0	$4,000
29	0500-New facility - Network/Security Infrastructure	B. Sugg	$0	$3,350	$0	$3,350

Ref #	Project	Responsible Director	Cap Ex 2010	Cap Ex 2011	Cap Ex 2012	Total
30	0100- SPP Facilities Occupation of New Data/Ops	M. See	$0	$15	$0	$15
31	0500-New Facility - Primary Operations Hardware	B. Sugg	$0	$528	$0	$528
32	0100-SPP Facilities Furnishings-New Office Building	M.See	$0	$6,000	$6,000	$12,000
33	0100-SPP Facilities Occupation of New Office Building	M.See	$0	$50	$50	$100
	New Facility Initiatives Totals		$35,046	$48,213	$11,213	$94,472
34	8000-Smart Grid Demonstrations for Integrating Dist Res	B. Rew	$0	$0	$0	$0
35	8000-EPRI Research Portfolio	B. Rew	$0	$0	$0	$0
	Ongoing Programs Studies Totals		$0	$0	$0	$0
36	0600- eterra Settlement Enhancement Foundation	P. Bruich	$250	$0	$0	$250
37	0800- PRR Implementation - Operations Foundation	L. Nickell	$700	$500	$200	$1,400
38	0840-MOS Enhancements Foundation	L. Nickell	$200	$200	$67	$467
39	0840-OATI Enhancements	L. Nickell	$200	$150	$125	$475
40	0830-EMS Enhancements Foundation	L. Nickell	$100	$100	$100	$300
	Operations / Market Enhancements Totals		$1,450	$950	$492	$2,892
41	0860-Improved Intermittent Resource Integration in EIS Mkt	L. Nickell	$750	$0	$0	$750
42	0860-OPS1 Replacement	L. Nickell	$100	$0	$0	$100
43	0860-Enhanced Ops Engineering (Voltage) Analysis	L. Nickell	$50	$0	$0	$50
44	0830-Centralized Modeling Tool	L. Nickell	$800	$0	$0	$800
45	0800-Add'l Work Space for Maumelle Ops Center	L. Nickell	$50	$0	$0	$50
46	0840-Ops Console Layout and Equipment Changes	L. Nickell	$100	$100	$100	$300
47	0840-Ops Emergency Communications Tools	L. Nickell	$0	$0	$0	$0
48	0820-Automate the Backup RSS Process	L. Nickell	$140	$0	$0	$140
49	0830-Model Change Submission Tool	L. Nickell	$200	$0	$0	$200
	Operations Initiatives Totals		$2,190	$100	$100	$2,390
50	0240-ERMS-Enterprise Records Management System	L. Krigbaum	$165	$0	$0	$165
51	0590-0340 Desk Qualification Training	M. Desselle	$20	$5	$0	$25
52	0340-Enterprise Learning Solutions	M. Desselle	$105	$75	$0	$180
53	0523-0340 Customer Training	M. Desselle	$92	$2	$0	$94
	Process Integrity Totals		$382	$82	$0	$464
54	0900- e-Tariff System	H. Starnes	$225	$40	$42	$307
	Regulatory Totals		$225	$40	$42	$307
	Totals for Above the line Projects		$73,301	$80,049	$23,357	$176,707

Financing Strategy

- **Three primary needs:**
  - **New Facility**
  - **Future Markets**
  - **Maintenance CapEx**

Projected Capex ($ Millions)	2010	2011	2012
New Facility	35.0	30.8	5.2
Future Markets	26.7	24.8	10.7
Maintenance CapEx	12.4	26.8	10.8
	74.1	82.3	26.7

- **Current Market**
  - **Spreads approx 120bps**
  - **Treasuries are low**
  - **Bank market very conservative**

Financing Strategy

- **SPP Proposed Strategy**
  - **Delay placement of maintenance capex financing**
  - **New Facility debt under 32 year note w/ 2 years interest only**
  - **Future Market debt under 14 year note w/ 4 years interest only**
  - **Maintenance capex financing under 5 year notes w/ level amortization**

Financing Strategy

- **SPP Proposed Strategy**
  - **Engage agent to market SPP debt in the private institutional market (New Facility & Future Market)**
    - **Pros**
      - **Active in utility space (recent placements by RTOs)**
      - **Flexibility in terms (longer term notes)**
      - **Aggressive pricing**
    - **Cons**
      - **Placement fee (prior bank deals issued w/o fee)**
      - **Quick funding (not flexible for delayed funding w/o rate risk)**

Financing Strategy

- **Actions Completed**
  - **Interviews w/ Comm'l Banks, Investment Bank, Placement Agents**
  - **Approvals for issuance received from FERC and AR PSC**
- **Next Steps**
  - **Finance Committee Consensus on Strategy/Structure**
  - **Engage Agent**
  - **Market Issuance (4 wks after agent engaged)**
  - **Issue Notes (4 wks after marketing)**

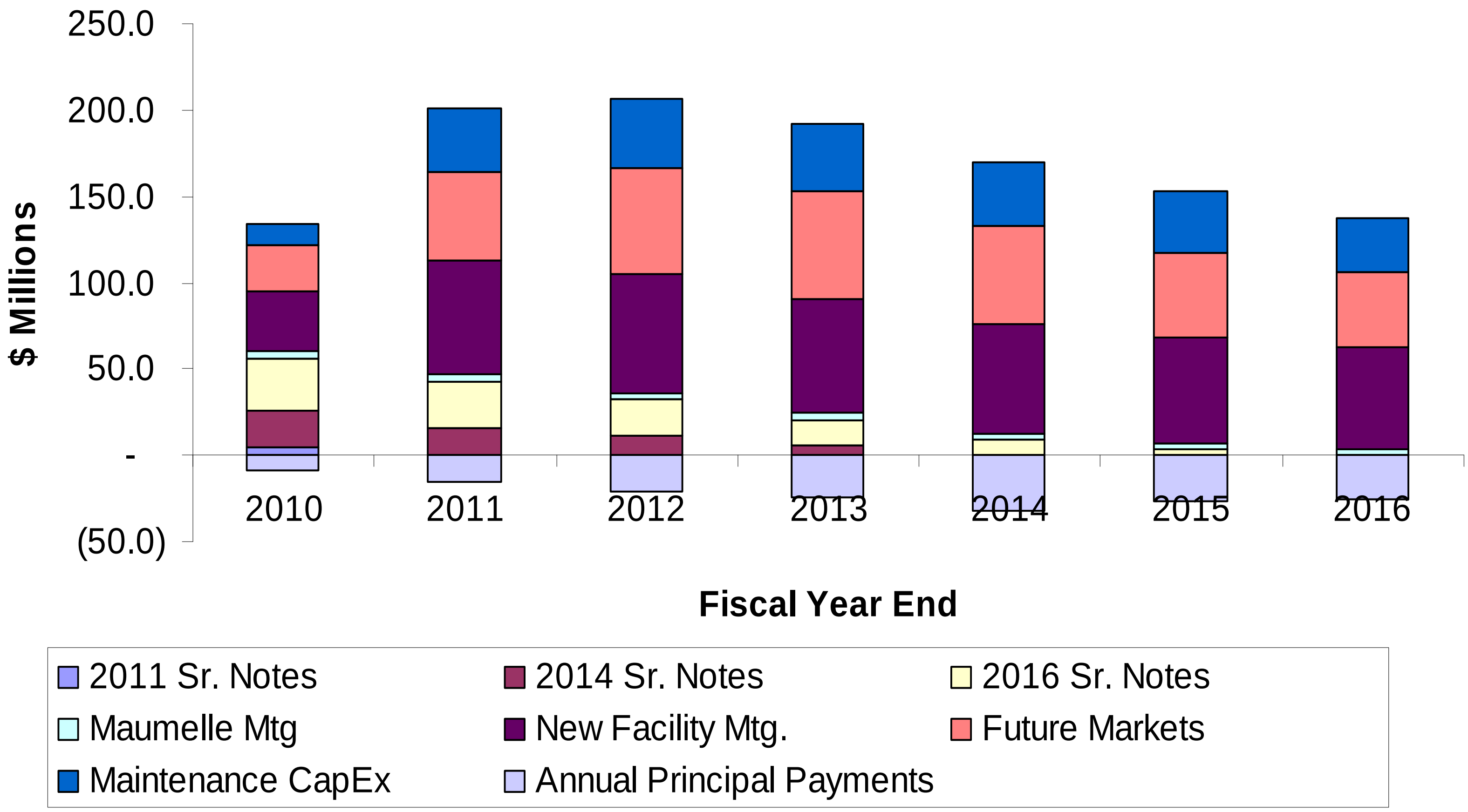
Indicative new issue pricing assuming an A rating from Fitch (February 4, 2010)

Maturity or Average Life (years)	5	7	10	12	15	20	30
Benchmark treasury	2.250% due 1/15	3.125% due 1/17	3.375% due 11/19	3.375% due 11/19	3.375% due 11/19	4.375% due 11/39	4.375% due 11/39
Treasury yield (%)	2.38	3.13	3.68	3.68	3.68	4.62	4.62
Credit spread (bps)	**105 - 115**	**105 - 115**	**110 - 120**	**120 - 130**	**135 - 145**	**125 - 135**	**130 - 140**
Coupon (%)	3.43 - 3.53	4.18 - 4.28	4.78 - 4.88	4.88 - 4.98	5.03 - 5.13	5.87 - 5.97	5.92 - 6.02
Swap to 3m$L (bps)	74 - 84	90 - 99	99 - 109	91 - 101	80 - 90	148 - 158	143 - 153

Indicative new issue pricing assuming an A rating from Fitch (November 8, 2009)

Maturity or Average Life (years)	5	7	10	12	15	20	30
Benchmark treasury	2.375% due 10/14	3.125% due 10/16	3.625% due 8/19	3.625% due 8/19	3.625% due 8/19	4.500% due 8/39	4.500% due 8/39
Treasury yield (%)	2.29	2.99	3.49	3.49	3.49	4.39	4.39
Credit spread (bps)	**115 - 125**	**115 - 125**	**115 - 125**	**125 - 135**	**140 - 150**	**130 - 140**	**135 - 145**
Coupon (%)	3.44 - 3.54	4.14 - 4.24	4.64 - 4.74	4.74 - 4.84	4.89 - 4.99	5.69 - 5.79	5.74 - 5.84
Swap to 3m$L (bps)	80 - 90	97 - 107	103 - 113	97 - 107	87 - 97	154 - 164	148 - 158

Projected Debt Schedule



130 FERC ¶ 61,055
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

Docket No. RM10-13-000

Credit Reforms in Organized Wholesale Electric Markets

(Issued January 21, 2010)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing, pursuant to section 206 of the Federal Power Act, to amend its regulations to reform credit practices in organized wholesale electric markets to ensure that credit practices result in jurisdictional rates that are just and reasonable. The Commission seeks public comment on the proposed regulations.

COMMENT DATE: Comments are due [insert date that is 60 days after publication in the **FEDERAL REGISTER**].

ADDRESSES: You may submit comments identified in Docket No. RM10-13-000, by one of the following methods:

- Agency Web Site: http://www.ferc.gov. Follow the instructions for submitting comments via the eFiling link found in the Comment Procedures section of the preamble.

- Mail: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to the Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, N.E., Washington, D.C. 20426. Please refer to the Comment Procedures section of the preamble for additional information on how to file paper comments.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

130 FERC ¶ 61,055
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Credit Reforms in Organized Wholesale Electric Markets — Docket No. RM10-13-000

NOTICE OF PROPOSED RULEMAKING

(Issued January 21, 2010)

I. Introduction

1. Pursuant to section 206 of the Federal Power Act (FPA),[1] the Commission is proposing to revise Part 35 of Title 18 of the Code of Federal Regulations (CFR) to reform credit practices in organized wholesale electric markets.[2] While this matter has been one of ongoing Commission interest, the recent turmoil in financial markets has emphasized the importance of sound credit practices that provide competitive markets with adequate access to capital without excessive risk and without excessive cost. Credit

[1] 16 U.S.C. 824e. Accord 16 U.S.C. 824d (providing that rates must be just and reasonable).

[2] For purposes of this Notice of Proposed Rulemaking, organized wholesale electric markets include energy, transmission and ancillary service markets operated by independent system operators and regional transmission organizations. These entities are responsible for administering electric energy and financial transmission rights markets. As public utilities, they have on file as jurisdictional tariffs the rules governing such markets.

policies are particularly important in the organized energy markets, in which regional transmission organizations (RTOs) and independent system operators (ISOs) must balance the need for market liquidity against corresponding risk. In order to ensure that credit policies result in jurisdictional rates that are just and reasonable, the Commission proposes to require RTOs and ISOs to adopt tariff revisions reflecting these proposed credit reforms. The Commission seeks public comment on these proposed reforms.

II. Background

2. The Commission has long been interested in credit policies in wholesale electric markets. The Commission considered issues related to credit practices in 1996 in crafting the pro forma Open Access Transmission Tariff (OATT) in Order No. 888,[3] where it directed that each transmission provider's tariff include reasonable creditworthiness provisions, and again in 2004 in a subsequent policy statement that provided additional

[3] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,937 (1996) (pro forma OATT, section 11 (Creditworthiness)), order on reh'g, Order No. 888-A, 62 FR 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

guidance regarding creditworthiness.[4] Since then, the individual organized wholesale electric markets have developed credit practices on a case-by-case basis, in response to individual concerns and issues and with varying levels of stakeholder support. More recently, some in the industry have expressed concern that these credit practices may no longer be adequate to protect the integrity of these markets and, in turn, to protect consumers from the high costs that would flow from excessive defaults and associated risks in the markets.

3. Credit practices and related risk management tools within organized wholesale electric markets have developed incrementally. Until the 1980s, electricity was generally produced and consumed within a single utility system, or bought from neighboring traditional utility suppliers. Because the risk of non-performance was deemed minimal, collateral requirements and other credit practices were not rigidly managed. Credit practices began to evolve with the development of independent generators and then with increased bulk trading between traditional utilities and independent generators and marketers in the 1990s. Credit practices further progressed in this decade, as power trading with multiple counterparties became a recognized multi-billion dollar industry.

[4] Policy Statement on Electric Creditworthiness, 109 FERC ¶ 61,186 (2004) (Policy Statement).

4. Today, parties operating outside the organized wholesale electricity markets typically use bilateral contracts such as the Western Systems Power Pool (WSPP) standard contract and the Edison Electric Institute (EEI) standard contract to sell power, managing credit risk within the terms of those agreements. However, the majority of transactions based on quantity and volume is in the organized wholesale electric markets.[5] Individual RTOs and ISOs developed their own individual processes for assessing risk, extending unsecured credit, and settling accounts.

5. To a large degree, early credit policies in the organized wholesale electric markets were based on the practices of their transmission owning members. In Order No. 888, the Commission required each transmission provider to have "reasonable credit review procedures … in accordance with standard commercial practices,"[6] but otherwise allowed the transmission provider to develop its own individual credit practices.[7] As the organized markets were being formed, they tended to use practices based on those of their transmission-owning members.

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[5] FERC Staff, 2008 State of the Markets Report, 51 (Sept. 2009).

[6] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,937.

[7] While the OATT applies to transmission providers, since 1996 a number of transmission providers have developed RTOs and ISOs.

6. Over time, the credit policies in each RTO and ISO have evolved and, in November 2004, the Commission issued its Policy Statement on Electric Creditworthiness to encourage consideration of specific reforms.[8] In particular, the Commission recommended that transmission providers establish qualitative and quantitative measures to assess credit risk and post those measures on their Open Access Same-Time Information System (OASIS) websites or in their tariffs. Further, the Commission recommended that organized wholesale electric markets seek to minimize the risk of default by shortening the settlement period, netting obligations owed by and to market participants wherever possible, and adopting other measures.

7. Subsequent to the Policy Statement, various proposals to amend credit policies have been filed by RTOs and ISOs and accepted by the Commission. PJM Interconnection, LLC (PJM), for example, has made several filings revising its tariff to modify its credit practices. The Commission recently accepted PJM's proposal to revise its tariff to reduce its settlement cycle from 30 days to seven days, reduce the amount of unsecured credit allowed to $50 million for a member company and $150 million for an affiliated group, and eliminate unsecured credit in the financial transmission rights

[8] See supra note 4.

market.[9] Earlier, the Commission accepted a shortened period to cure defaults and other tariff revisions intended to improve credit practices.[10]

8. Likewise, the Commission has accepted recent tariff revisions filed by California Independent System Operator Corporation (CAISO), reducing the level of unsecured credit that may be obtained by a market participant from $250 million to $150 million,[11] and eventually to $50 million.[12] The Commission has also accepted CAISO's proposal to shorten its "settlement and payment period" from more than 80 days to approximately 25 days.[13]

9. Notwithstanding the progress that has been made in some of the organized wholesale electric markets in reforming credit practices, the Commission is concerned that more needs to be done to ensure that rates for service in those markets are just and reasonable. Past experience in the markets has highlighted aspects of the credit

[9] PJM Interconnection, L.L.C., 127 FERC ¶ 61,017, at P 4 (2009).

[10] PJM Interconnection, L.L.C., 126 FERC ¶ 61,084 (2009).

[11] California Independent System Operator Corp., 126 FERC ¶ 61,285 (2009).

[12] California Independent System Operator Corp., 129 FERC ¶ 61,142 (2009).

[13] California Independent System Operator Corp., 128 FERC ¶ 61,265, at P 4 (2009).

management tools that require modification,[14] as was emphasized at a technical conference on credit and capital issues held by the Commission in January 2009.[15] Concerns of default, especially large defaults that have not been minimized by market safeguards, are troubling in the organized wholesale electric markets, in which losses due to default are borne among all market participants.[16] As part of our continuing oversight and assessment of these markets, the Commission is acting today to ensure that the credit policies in place in those markets are sufficient to reasonably protect consumers against the adverse effects of default.

III. Discussion

10. Given a decade or more of experience and evolution by the markets with credit practices, the Commission believes that it is appropriate to now consider adoption of

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[14] See New England Power Pool, 97 FERC ¶ 61,387 (2001) (accepting alternative payment and financial assurance arrangements filed by NEPOOL in response to defaults associated with the bankruptcy of Enron).

[15] Testimony in Technical Conference on Credit and Capital Issues, Docket No. AD09-2-000, Tr. 91:23-25 (Mr. Robert Ludlow, Vice President and Chief Financial Officer, ISO-NE) (Jan. 13, 2009); Testimony in Technical Conference on Credit and Capital Issues, Docket No. AD09-2-000, Tr. 101:3-5 (Mr. Philip Leiber, Chief Financial Officer and Treasurer, CAISO) (Jan. 13, 2009).

[16] Policy Statement, 109 FERC ¶ 61,186 at P 17 ("If collateral posted by a defaulting party is not sufficient to cover the amount of its default, the remaining credit risk exposure and costs are socialized across an ISO's/RTO's members.").

specific requirements regarding credit practices for organized wholesale electric markets, to be set forth in the Commission's regulations. To promote confidence in the markets, the Commission proposes reforming credit practices of the organized wholesale electric markets to limit potential future market disruptions and to dampen the possible ripple effect of such disruptions. These reforms include shortening settlement periods and reducing the amount of unsecured credit, as described below. The Commission believes that these reforms, if adopted, will enhance certainty and stability in the markets and, in turn, ensure that costs associated with market participant defaults do not result in unjust or unreasonable rates.

11. The Commission also notes that some market participants may pose different credit risks than others. For instance, Mr. Robert Levin stated that, in his experience, "[in] discussing it with a number of the ISOs and RTOs, and it was certainly brought to our attention, that [municipalities] are pretty good credit risks."[17] Thus, the Commission requests comment on whether the credit practices discussed below should be applied in the same way to all market participants or whether they should be applied differently to certain market participants depending on their characteristics.

[17] Testimony in Technical Conference on Credit and Capital Issues, Docket No. AD09-2-000, Tr. 133:12-14 (Mr. Robert Levin, Managing Director, Energy Research, Chicago Mercantile Exchange) (Jan. 13, 2009).

12. While the Commission proposes that the tariff changes be submitted no later than June 30, 2011, to go into effect no later than 60 days after filing, the Commission also requests comment on whether the changes proposed should be put in place earlier. In proposing this deadline, the Commission seeks to balance the needs of the organized wholesale electric markets to modify their practices to comply with the proposed reforms against the benefits to the markets and consumers of having the reforms in place before the winter peak season in 2011-2012. In addition, the Commission specifically requests the views of the ISO's and RTO's managements, as the entities responsible for administering these markets, on each of the proposals set forth below.[18]

A. Shortening the Settlement Cycle

13. The length of the settlement (i.e., billing) period raises both cash management and risk issues. As discussed in our Policy Statement, the size of credit risk exposure is, in large part, a function of the length of time between completion of the various parts of electricity transactions, i.e., the provision of service, the billing for service, and the payment for service. Since the risk of default begins at the time the product or service is committed for delivery and continues until the account payable is ultimately extinguished, reductions in settlement periods would serve to: (1) lower the level of

[18] The views of management may be expressed through the ISO-RTO Council (IRC).

financial assurances required (i.e., collateral requirement provided by individual participants); (2) reduce the quantity of the aggregate level of payables outstanding at any point in time, thereby reducing the potential exposure of a defaulting entity; (3) enable updated transaction prices and charges to be utilized in a timely manner in determining credit risk exposure; and (4) provide earlier identification of default situations by lessening the opportunity for an unrecognized default and its severity. Accordingly, the Commission believes that ISOs/RTOs can minimize the exposure period and significantly reduce the credit risk to all market participants by reducing the time between when a cost is incurred and when payment is ultimately received by an ISO/RTO (i.e., shortening the settlement period).[19]

14. PJM has since commissioned a study that concluded, among other things, that shorter settlement periods would reduce default exposures. Based on this analysis, PJM estimated when it filed for weekly billing that the total credit risk exposure would be reduced by $2.1 billion (68 percent) and the necessary financial security provided by members would be reduced by $700 million (73 percent).[20]

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[19] Policy Statement, 109 FERC ¶ 61,186 at P 21.

[20] PJM Credit & Clearing Analysis Project: Findings & Recommendations (June 2008) (found on Dec. 31, 2009 at: http://www.pjm.com/~/media/committees-

(continued…)

15. The Commission proposes to revise its regulations to require that each RTO and ISO include in the credit provisions of its tariff revisions to implement a settlement cycle of no more than seven calendar days with no more than an additional seven calendar days for final payment. The Commission recognizes that software system adjustments may be necessary and is also aware that similar system changes have resulted in significant delays of other market changes.[21] The Commission further requests comment on the practicality of organized wholesale electric markets implementing daily settlement periods within one year of implementation of weekly settlement periods.

16. We recognize that net wholesale buyers in organized wholesale electric markets may incur cash management costs by paying within the shortened timeframe, given that they receive revenues from their own retail buyers on a 30-day basis.[22] To reconcile the discrepancy in cash flow, a market participant may need to arrange cash management

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groups/committees/mc/20080626-item-03d-crmsc-market-reform-credit-recommendations.ashx).

[21] To the extent possible, the Commission encourages use of software already used in markets that are currently operating on a seven-day settlement timeframe. For example, PJM and ISO-NE already use a seven day settlement timeframe. PJM Interconnection, L.L.C., 127 FERC ¶ 61,017 at P 4; New England Power Pool, 107 FERC ¶ 61,201, at P 10-12 (2004).

[22] See Testimony in Technical Conference on Credit and Capital Issues, Docket No. AD09-2-000, Tr. 146:3-9 (Mr. Daniel Sarti, Credit Risk Manager, Arizona Public Service Company) (Jan. 13, 2009).

facilities to manage the more frequent payments. The Commission invites comments on this proposal, and whether it would involve a one-time cost to establish such a facility or ongoing costs that could significantly affect liquidity and rates.

B. Use of Unsecured Credit

17. As suggested above, as the timeframe of settlement shrinks, so does the amount of unsecured credit that a participant may need. This is because the number of outstanding transactions and the size of the amounts outstanding become smaller, thus minimizing the credit exposure to any market participant.[23]

18. While RTOs and ISOs have tightened risk and credit standards over the years, the vestiges of the practices historically used for unsecured credit are still substantial in some markets. Following those practices, RTOs and ISOs, after credit analysis, generally allow significant amounts of unsecured credit. The Commission understands that the level of unsecured credit allowed has also varied widely among the organized wholesale electric markets (during the financial crisis in fall 2008, ranging from 50 to 80 percent).

19. The Commission proposes to revise its regulations to require that each RTO and ISO include in the credit provisions of its tariff revisions to reduce the extension of

[23] See California Independent System Operator Corp., 129 FERC ¶ 61,142 at P 14 (adopting limit of $50 million of unsecured credit per market participant); PJM Interconnection, L.L.C., 127 FERC ¶ 61,017 at P 5 (adopting limit of $50 million for a member company and $150 million for an affiliated group).

unsecured credit to no more than $50 million per market participant. The Commission seeks comment on whether there should be a further aggregate cap to cover an entire corporate family (e.g., holding company, subsidiaries, associates, and affiliates) and also whether the cap should be different for markets of different sizes. Reducing the level of unsecured credit combined with shortening the settlement timeframe should reduce the risk of default and consequently reduce the cost of default that is shared among market participants.

20. The Commission further requests comment on the practicality of eliminating unsecured credit in connection with adopting daily settlement within one year of implementation of weekly settlement periods.

C. <u>Financial Transmission Rights Markets</u>

21. The above-proposed reforms are not directly applicable to markets for financial transmission rights, because financial transmission rights have a longer-dated obligation to perform which can run from a month to a year or more. The Commission has also noted that financial transmission rights markets have unique risks that distinguish them from other wholesale electric markets, and that the value of a financial transmission right depends on unforeseeable events, including unplanned outages and unanticipated weather

conditions.[24] Moreover, financial transmission rights are relatively illiquid, adding to the inherent risk in their valuation.[25]

22. For example, PJM suffered a significant default in December 2007 in its financial transmission rights market[26] and moved to eliminate the use of unsecured credit in that market due to its risk.[27] That default illustrates the unique risk of financial transmission rights. Given a change in market conditions, a set of financial transmission rights positions became highly unprofitable. Because financial transmission rights obligations cannot be terminated prior to the expiration of the contract, from one month to several years, losses can mount to the point that the financial transmission right holder goes bankrupt.

23. Given the unique characteristics of and risks inherent in financial transmission rights markets, the Commission therefore proposes to revise its regulations to require that

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[24] For a financial transmission right, an unexpected outage can cause unforeseen congestion or movement in flows and the resulting charges or credits can swing very substantially either way.

[25] PJM Interconnection, L.L.C., 127 FERC ¶ 61,017 at P 36.

[26] PJM Interconnection, L.L.C., 122 FERC ¶ 61,279, at P 26 n.10 (2008) (citing defaults by Exel and Power Edge in PJM's financial transmission rights market).

[27] PJM Interconnection, L.L.C., 127 FERC ¶ 61,017 at P 8, 36.

each RTO and ISO include in the credit provisions of its tariff provisions that eliminate unsecured credit in financial transmission rights markets.

D. Ability to Offset Market Obligations

24. Organized wholesale electric markets typically arrange for settlement and netting of transactions entered into between market participants and the market administrator, but do not take title to the underlying contract position of a participant at the time of settlement. This practice became an issue during the Mirant bankruptcy and its resulting default in the CAISO market. Because CAISO had not "taken title" of the transactions, CAISO could not net payments owed to Mirant against payments owed by Mirant.[28] As a result, all of Mirant's creditors had a claim to revenues owed to Mirant by CAISO market participants, but CAISO market participants bore the loss for money owed and not paid by Mirant.

25. The Commission therefore proposes to revise its regulations to require that each RTO and ISO include in the credit provisions of its tariff revisions to clarify their status as a party to each transaction so as to eliminate any ambiguity or question as to their ability to manage defaults and to offset market obligations. The Commission seeks

[28] Memorandum by Wachtell, Lipton, Rosen & Katz to PJM regarding Setoffs and Credit Risk of PJM in Member Bankruptcies at 7, 10-11 (Mar. 17, 2008) (found on Dec. 31, 2009 at http://www.pjm.com/~/media/committees-groups/committees/crmsc/20080423/20080423-wachtell-netting-memo.ashx).

comment on whether this clarification of status would have ramifications beyond addressing the risk highlighted here.

E. Minimum Criteria for Market Participation

26. The Commission recognizes that trading helps provide market liquidity, but trading by undercapitalized entities without adequate risk management procedures in place poses an unwarranted risk to organized wholesale electric markets and to their market participants. Minimum criteria for market participation, such as the capability to engage in risk management or hedging or to out-source this capability with periodic compliance verification, are intended to make sure that each market participant has at its disposal adequate risk management capabilities and adequate capital to engage in trading with minimal risk, and related costs, to the market as a whole. Minimum criteria should not be onerous, however, and should allow most traditional market participants – including small load-serving entities, municipalities, cooperatives, and other similar participants in organized wholesale electric markets – to participate.

27. The Commission therefore proposes to revise its regulations to require that each RTO and ISO include in the credit provisions of its tariff language to specify minimum participation criteria for all market participants. The Commission requests comment on what the minimum criteria should be, as well as the process by which the organized wholesale electric markets adopt such criteria.

F. "Material Adverse Change"

28. Many wholesale market tariffs allow a market administrator to require additional collateral if there is a "material adverse change" in the market participant's credit status.

However, this phrase is ambiguous and could lead to uncertainty as to when a market administrator can require the posting of additional collateral, at potentially great cost to the market participant. Additionally, this ambiguity may have the practical effect of delaying a market administrator's request for additional collateral until the last minute, by which time the market participant may find it difficult or impossible to obtain and provide such collateral. The mere request for collateral at such a late date could even lead to reactions from other market participants that result in defaults.

29. The Commission therefore proposes to revise its regulations to require that each RTO and ISO include in the credit provisions of its tariff language to specify under what circumstances a market administrator may invoke a "material adverse change" as a justification for requiring additional collateral. The Commission requests comment as to specific language regarding the circumstances under which a market administrator may invoke the "material adverse change" provision and the process by which the organized wholesale electric markets would adopt such language.

G. <u>Grace Period to "Cure" Collateral Posting</u>

30. RTOs and ISOs have also adopted timeframes in which a party may "cure" its changed credit position by posting additional collateral. The standardized timeframe helps eliminate uncertainty for other market participants during periods of credit stress.

PJM, for example, has adopted a period of two business days to cure.[29] The Commission understands that demanding additional collateral from a participant can complicate that participant's financial position and that the participant may need time to "cure," including consulting with potential lenders and others. On the other hand, the Commission is also aware that the time period to "cure" the position of the participant must be short enough to minimize uncertainty for other market participants and to stem accumulation of debt and potentially erratic market behavior.

31. For these reasons, the Commission proposes to revise its regulations to require that each RTO and ISO include in the credit provisions of its tariff language to limit the time period allowed to post additional collateral when additional collateral is requested by the organized wholesale electric market. The Commission requests comment on the appropriate time period to post additional collateral, e.g., two business days, as PJM has adopted, and whether the time period should be standardized among organized wholesale electric markets.

IV. Environmental Analysis

32. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect

[29] PJM Interconnection, L.L.C., 126 FERC ¶ 61,084 at P 12.

on the human environment.[30] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment.[31] The proposed regulations are categorically excluded as they address rate filings submitted under section 206 of the FPA and the establishment of just and reasonable rates, terms and conditions of jurisdictional service under this section of the FPA.[32] Accordingly, no environmental assessment is necessary and none has been prepared for this NOPR.

V. Information Collection Statement

33. The Office of Management and Budget's (OMB) regulations require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

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[30] Regulations Implementing the National Environmental Policy Act, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990, ¶ 30,783 (1987).

[31] 18 CFR 380.4.

[32] See 18 CFR 380.4(a)(15).

34. This NOPR proposes to amend the Commission's regulations pursuant to section 206 of the Federal Power Act, to reform credit practices of organized wholesale electric markets to limit potential future market disruptions. To accomplish this, the Commission proposes to require RTOs and ISOs to adopt tariff revisions reflecting these credit reforms. Such filings would be made under Part 35 of the Commission's regulations. The information provided for under Part 35 is identified as FERC-516.

35. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

Burden Estimate: The Public Reporting burden for the requirements contained in the NOPR is as follows:

Data Collection	Number of Respondents	No. of Responses	Hours Per Response	Total Annual Hours
FERC-516				
Transmission Organizations with Organized Electricity Markets	6	1	60	360

Information Collection Costs: The Commission seeks comments on the costs to comply with these requirements. The Commission has projected the average annualized cost of all respondents to be the following: 360 hours @ $300 per hour = $108,000 for respondents. No capital costs are estimated to be incurred by respondents.

Title: FERC-516 "Electric Rate Schedule Tariff Filings"

Action: Proposed Collections

OMB Control No: 1902-0096

Respondents: Business or other for profit, and/or not for profit institutions.

Frequency of Responses: One time to initially comply with the rule, and then on occasion as needed to revise or modify.

36. Necessity of the Information: The information from FERC-516 enables the Commission to exercise its wholesale electric power and transmission oversight responsibilities in accordance with the Federal Power Act. The Commission needs sufficient detail to make an informed and reasonable decision concerning the appropriate level of rates, and the appropriateness of non-rate terms and conditions, and to aid customers and other parties who may wish to challenge the rates, terms, and conditions proposed by the utility.

37. This proposed rule, if adopted, would amend the Commission's regulations to ensure that credit practices currently in place in markets reasonably protect consumers against the adverse effects of default. To promote confidence in the markets, the Commission believes it is appropriate to consider adoption of specific requirements regarding credit practices for organized wholesale electric markets. These requirements include shortening of settlement periods and reducing the amount of unsecured credit.

The Commission believes these actions, if they are adopted, will enhance certainty and stability in the markets, and in turn, ensure that costs associated with market participant defaults do not result in unjust or unreasonable rates.

38. Internal review: The Commission has reviewed the requirements pertaining to organized wholesale electric markets and determined the proposed requirements are necessary to its responsibilities under section 206 of the Federal Power Act.

39. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

40. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502-8415, fax: (202) 273-0873, e-mail: michael.miller@ferc.gov]. Comments on the requirements of the proposed rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission], e-mail: oira_submission@omb.eop.gov.

VI. Regulatory Flexibility Act Certification

41. The Regulatory Flexibility Act of 1980 (RFA)[33] requires agencies to prepare certain statements, descriptions, and analyses of proposed rules that will have significant economic impact on a substantial number of small entities.[34] Agencies are not required to make such an analysis if a rule would not have such an effect.

42. The RTOs and ISOs regulated by the Commission do not fall within the RFA's definition of small entity.[35] In addition, the vast majority of market participants in RTOs and ISOs are, either alone or as part of larger corporate families, not small entities. And the protections proposed here will protect all market participants, including small market

[33] 5 U.S.C. 601-12.

[34] The RFA definition of "small entity" refers to the definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. 15 U.S.C. 632. The Small Business Size Standards component of the North American Industry Classification System defines a small electric utility as one that, including its affiliates, is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and whose total electric output for the preceding fiscal year did not exceed 4 million MWh. 13 CFR 121.201.

[35] 5 U.S.C. 601(3), citing to section 3 of the Small Business Act, 15 U.S.C. 632. Section 3 of the Small Business Act defines a "small-business concern" as a business which is independently owned and operated and which is not dominant in its field of operation.

participants, by reducing the likelihood of defaults and minimizing the impact of any defaults.

43. California Independent Service Operator Corp. is a nonprofit organization comprised of more than 90 electric transmission companies and generators operating in its markets and serving more than 30 million customers.

44. New York Independent System Operator, Inc. (NYISO) is a nonprofit organization that oversees wholesale electricity markets serving 19.2 million customers. NYISO manages a 10,775-mile network of high-voltage lines.

45. PJM Interconnection, L.L.C. is comprised of more than 450 members including power generators, transmission owners, electricity distributors, power marketers and large industrial customers and serving 13 states and the District of Columbia.

46. Southwest Power Pool, Inc. is comprised of 50 members serving 4.5 million customers in eight states and has 52,301 miles of transmission lines.

47. Midwest Independent Transmission System Operator, Inc. (Midwest ISO) is a non-profit organization with over 131,000 megawatts of installed generation. Midwest ISO has 93,600 miles of transmission lines and serves 15 states and one Canadian province.

48. ISO New England Inc. (ISO-NE) is a regional transmission organization serving six states in New England. The system is comprised of more than 8,000 miles of high voltage transmission lines and several hundred generating facilities of which more than 350 are under ISO-NE’s direct control.

49. Therefore, the Commission certifies the proposed rule will not have a significant economic impact on a substantial number of small entities. As a result, no regulatory flexibility analysis is required.

VII. Comment Procedures

50. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [insert date 60 days from publication in the **FEDERAL REGISTER**]. Comments must refer to Docket No. RM10-13-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments. Comments may be filed either in electronic or paper format.

51. Comments may be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats, but requests commenters to submit comments in a text-searchable format rather than a scanned image format. Commenters filing electronically do not need to make a paper filing. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, N.E., Washington, D.C., 20426.

52. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section

below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

53. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

54. From the Commission's Home Page on the Internet, this information is available in the Commission's document management system, eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number (excluding the last three digits of the docket number), in the docket number field.

55. User assistance is available for eLibrary and the Commission's website during normal business hours. For assistance, please contact FERC Online Support at (202) 502-6652 (toll-free at 1-866-208-3676) or e-mail at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

<u>List of subjects in 18 CFR Part 35</u>

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission. Commissioner Norris voting present.

(S E A L)

Kimberly D. Bose,
Secretary.

In consideration of the foregoing, the Commission proposes to amend part 35, Chapter J, Title 18, Code of Federal Regulations, as follows:

PART 35 – FILING OF RATE SCHEDULES AND TARIFFS.

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352.

2. Subpart J is added to read as follows:

SUBPART J – CREDIT PRACTICES IN ORGANIZED WHOLESALE ELECTRIC MARKETS

Sec.

35.45 Applicability

35.46 Definitions

35.47 Tariff provisions governing credit practices in organized wholesale electric markets

§ 35.45 Applicability.

This part establishes credit practices for organized wholesale electric markets for the purpose of minimizing risk to market participants.

§ 35.46 Definitions.

(a) Market Participant means an entity that qualifies as a Market Participant under 18 CFR 35.34.

(b) Organized Wholesale Electric Market includes an independent system operator and a regional transmission organization.

(c) Regional Transmission Organization means an entity that qualifies as a Regional Transmission Organization under 18 CFR 35.34.

(d) Independent System Operator means an entity operating a transmission system and found by the Commission to be an Independent System Operator.

§ 35.47 Tariff provisions regarding credit practices in organized wholesale electric markets.

Each organized wholesale electric market must have tariff provisions that:

(a) Limit the amount of unsecured credit extended to any market participant to no more than $50 million.

(b) Adopt a settlement period of no more than seven days and allow no more than an additional seven days to receive payment.

(c) Eliminate unsecured credit in the financial transmission rights market.

(d) Allow it to offset market obligations owed to market participants against market obligations owed by market participants.

(e) Limit to no more than two days the time period provided to post additional collateral when additional collateral is requested by the organized wholesale electric market.

(f) Provide minimum participation criteria required of market participants to be eligible to receive credit from the organized wholesale electric market.

(g) Specify when a market administrator may invoke the “material adverse change” as a justification for requiring additional collateral.