C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 20 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order approving the Open Access Transmission Tariff for the period beginning January 1, 2017 and for certain approvals incidental to such an order.

INFORMATION EXCHANGED BETWEEN MARITIME ELECTRIC COMPANY, LIMITED AND THE CITY OF SUMMERSIDE PRIOR TO MAY 31, 2017

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Sherri Quinn Jewell

From: Ryan MacDonald
Sent: Wednesday, December 07, 2016 9:18 AM
To: Spencer Campbell
Cc: Derek Key; Jeff Cormier; Greg Gaudet; Gordon MacFarlane; Bob Ashley
Subject: OATT Application

Morning Spencer,

We are writing further to our meeting of last week, which was, from our perspective, beneficial to all parties. From the City's perspective, it was a positive and worthwhile endeavor, as the exchange of information provided some clarity with respect to various policy considerations and methodologies contained within the current OATT, and showed a willingness from MECL to continue those discussions in an attempt to identify and narrow issues relating to the draft OATT document.

In order to continue that process, and as requested, we have set out some questions below. We are providing these questions on a without prejudice basis and in an effort to try and keep the dialogue open between the parties. If there are any items that you believe may require clarification, in order to determine exactly what information we may be seeking, please do not hesitate to contact me. However, at this point in our discussions, the questions that the City is posing to MECL are as follows:

1. Can you provide an indication as to the margins that you believe Suez may be achieving? There was reference to the "back of an envelope" calculation, but if an indication as to the range of margin can be provided, it would be appreciated.
2. Can you provide the coincident peak load on the electricity transmission system for each month over the last three years (36 months), including the values for the twelve month period used in MECL's recent transmission tariff application (i.e. 2014)? For each monthly peak value, can you also indicate the following:
   (a) Hour in which the peak load occurs.
   (b) A breakdown of each of the components of the monthly peak demand, including:
      (i) Demand by Maritime Electric's own customer base,
      (ii) Other users of Network service (if any),
      (iii) Firm Point to Point (PTP) reservations, and
      (iv) Any other demand contributing to the demand peak.
3. Wind generators are excluded from the third tier band of penalties on the Energy Imbalance service Schedule 4. Based on the fact that Summerside has embedded wind generation that affects it scheduling, how does MECL propose to deal with Summerside's energy imbalance due to forecasting errors?
4. How and where are the monies collected through the imposition of penalties for the energy imbalance service going to be applied?
5. If there is any accrual of funds from these penalties how will the accrual be refunded to users of the system?
6. What is the methodology behind the level of penalties chosen and the bands?
7. Can you provide a one line diagram of the MECL 69kv and 138kv grid, both before and after completion of line Y-104?

There are some additional items that we discussed, which we understand MECL is willing to consider. As such, we have not raised any of those specific issues in this correspondence, on the understanding that there will be an opportunity to revisit those specific issues in the future (i.e. participation in the Baseline Plan prior to its development, notion of an on-Island bypass for the City similar to the one now including for industrial users, etc.).

Once we have received the responses of MECL, and have had the opportunity to review them with the City, we will contact you with respect to a follow-up meeting to continue our conversations.

Additionally, it is our understanding that when the parties last appeared before the Commission, the direction given was to hold a stakeholder session, and to then advise the Commission as to the relevant dates and times for the exchange of interrogatories, the pre-filing of experts reports and ultimately the number of days that may be required for hearing. Given the direction that we have chosen to proceed, it would appear that we may not be in a position to provide the Commission with the information as directed.

Assuming an update to the Commission is required, it would appear that this may be accomplished by a letter to counsel for the Commission, but if you believe that an appearance may be required, we would be happy to have that discussion as well.

We look forward to receiving MECL's responses once the required information is available.
Ryan

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*Practising through a professional corporation

KEY MURRAY LAW

Sherri Quinn Jewell

From: Spencer Campbell <scampbell@stewartmckelvey.com>
Sent: Thursday, December 15, 2016 10:22 AM
To: Ryan MacDonald
Cc: Derek Key; Jeff Cormier
Subject: Responses for Summerside re OATT
Attachments: CP FERC tests.xlsx; Transmission System without Y104.pdf; Transmission system with Y104.pdf; Coincident peak loads.xlsx; Dec 7 2016 questions from Sside.docx; Bypass Attachment K applicability.docx

Ryan:

The purpose of this e-mail is to respond to four takeaways from the December 1 meeting in Summerside and the seven questions in your December 7 e-mail. If your client would like to meet to discuss this material in more detail let me know.

The four takeaways were:

1. **Is the 12 CP method that MECL has used in the OATT filing consistent with the FERC tests?** The analysis in the attached Excel workbook "CP FERC tests" shows that the 12 CP method marginally passes the FERC applicability tests. The alternate method would be 3CP, based on the peaks for the months of Dec, Jan and Feb, which are the months in which the annual peak is likely to occur. The analysis shows that for both methods, the transmission usage by the City of Summerside represents 7 % of the total Network Service and Point-to-Point transmission service for the year, which means that it would not provide a benefit to the City. Maritime Electric therefore proposes to continue with the 12 CP method. The Company also expects that monthly billing would be more complicated with the 3CP method.
2. **Where do the imbalance penalty premiums go?** Maritime Electric proposes that the penalty premiums will be accrued during the year and used to lower the rates for Network Service and Point-to-Point transmission service effective February 1 of the following year.
3. **What goes into the OATT rate base as a result of Maritime Electric's transmission planning?** See the response to Question 7 in the attached for Maritime Electric's proposed treatment for line Y-104.
4. **Is the Industrial bypass provision in Attachment K applicable to the City of Summerside?** The answer is no. See the attached Word document "Bypass per Attachment K".

For response to the seven questions in the December 7 e-mail, see the attached Word document "Dec 7 questions from Sside". The attached one-line transmission system diagrams are part of the response to Question 7.

A second email will follow shortly.

Spencer

vous avez reçu ce courriel par erreur, veuillez nous aviser et éliminer ce courriel, ainsi que les pièces jointes, de votre système informatique et de vos dossiers.

A

CP FERC tests MECL system
16-12-02

FERC TESTS FOR APPROPRIATENESS OF 12CP
DEMAND COST ALLOCATION METHODOLOGY

		PEI monthly net peak loads			
		2013 (MW)	2014 (MW)	2015 (MW)	
Jan		242.5	243.8	263.9	
Feb		240.0	236.9	254.1	
Mar		200.5	225.4	232.5	
Apr		185.5	196.4	198.4	
May		173.6	189.4	183.5	
Jun		183.4	181.0	182.7	
Jul		195.6	194.1	189.6	
Aug		186.0	195.0	204.9	
Sep		178.9	184.9	182.6	
Oct		188.9	195.6	193.0	
Nov		227.1	225.0	235.2	
Dec		251.8	254.5	240.6	
1CP	(highest monthly peak; i.e. annual peak)	251.8	254.5	263.9	
12CP	(average of the 12 monthly peaks)	204.5	210.2	213.4	
Low	(lowest monthly peak)	173.6	181.0	182.6	
On-peak	Ratio of average of Dec, Jan & Feb to 1CP	0.972	0.963	0.958	
Off-peak	Ratio of average of Mar to Nov to 1CP	0.759	0.780	0.759	
FERC tests for appropriateness of 12CP demand cost allocation methodology					Criteria for 12CP
1	Difference between On-peak and Off-peak	0.21	0.18	0.20	0.19 or less
2	Ratio of Low to 1CP	0.689	0.711	0.692	0.66 or higher
3	Ratio of 12CP to 1CP	0.812	0.826	0.809	0.81 or higher

CP FERC tests MECL system
16-12-02

NETWORK AND POINT-TO-POINT TRANSMISSION USAGE
(firm service or equivalent)

	2014 12CP (MW)	Allocation (%)	2014 3CP (Jan, Feb and Dec) (MW)	Allocation (%)
Long term firm Point-to-Point	-		-	
MECL Network	189.0	78.9	219.9	78.2
Summerside Network	-		-	
Summerside short term firm	10.0	4.2	10.0	3.6
Summerside non-firm	6.7	2.8	9.6	3.4
Merchant wind non-firm	33.7	14.1	41.8	14.9
Total	239.4	100.0	281.3	100.0

CP FERC tests MECL system
16-12-02

DEMAND DETERMINANTS FOR 2014 BASED ON 3CP

Services		2014 usage (MW)	2014 usage (MWh)	Transmission Service equivalent firm (MW)		Schedules 1 and 2 equivalent firm (MW)	
Long term firm Point-to-Point reservations		-		-		-	
Average of 12 CP for MECL load (Network)		189.0		189.0		189.0	
Average of 12 CP for Sside load (Network)		-		-		-	
Short term firm Point-to-Point service:							
- Summerside	(average for 12 months)	10.0		10.0		10.0	
Non-firm Point-to-Point service:							
- Summerside	on-peak		24,621	5.9	(Appalachian)	5.9	(Appalachian)
	off-peak		6,856	0.8		0.8	
- West Cape wind	on-peak		155,799	17.8	(non-Appalachian)	37.5	(Appalachian)
	off-peak		138,859	15.9		15.9	
				239.3		259.0	

Note: Summerside stopped purchasing from West Cape in October 2014. Therefore all West Cape generation has been shown as exported for sale off-Island for 2014. Also, Summerside's on-peak non-firm Point-to-Point service quantity has been increased by the amount purchased from West Cape during on-peak in 2014.

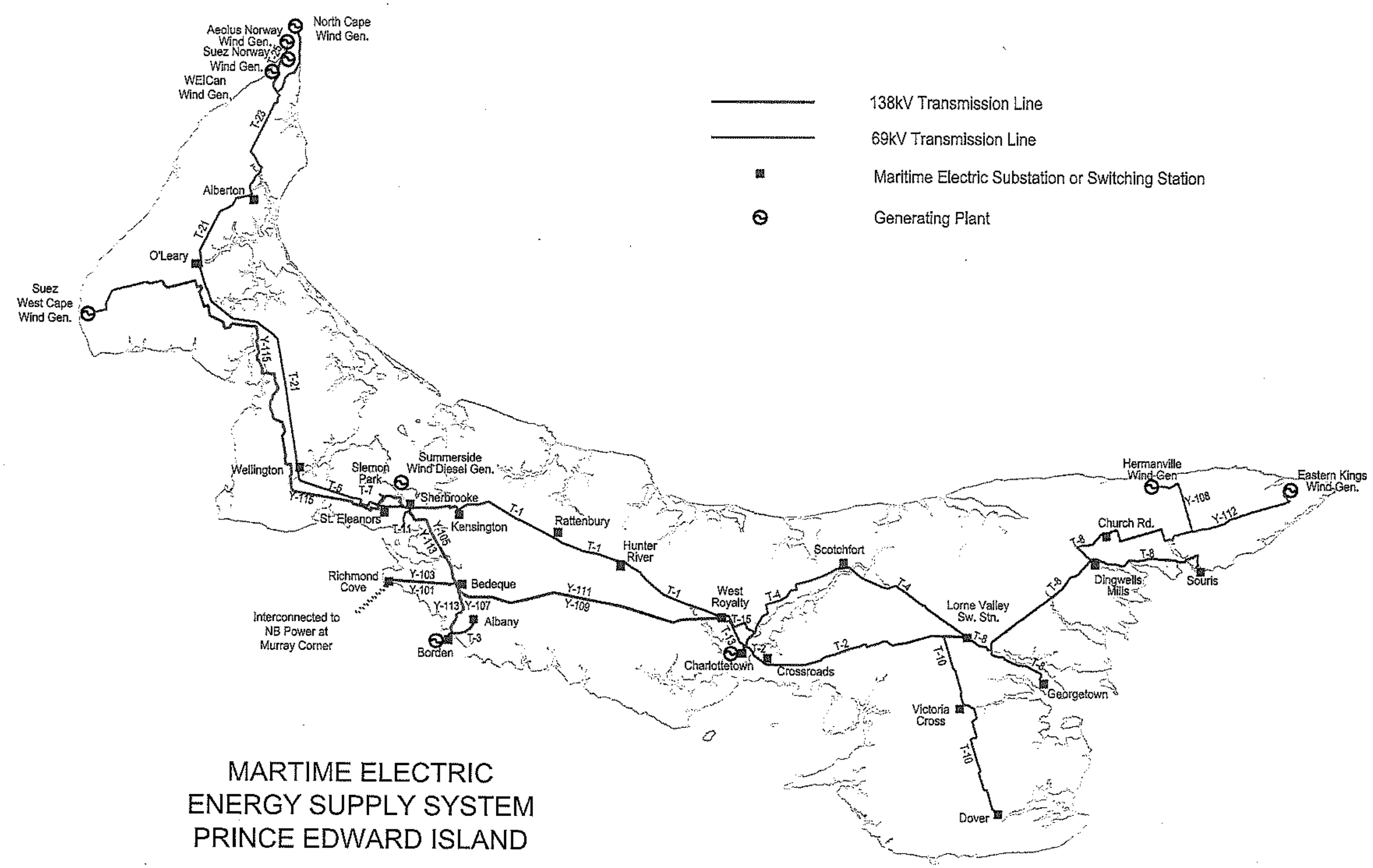
CP FERC tests MECL system
16-12-02

DEMAND DETERMINANTS FOR 2014 BASED ON 3CP
(Winter peaking months of Jan, Feb and Dec)

Services			2014 usage (MW)	2014 usage (MWh)	Transmission Service equivalent firm (MW)		Schedules 1 and 2 equivalent firm (MW)	
Long term firm Point-to-Point reservations			-		-		-	
Average of 3 CP for MECL load (Network)			219.9		219.9		219.9	
Average of 3 CP for Sside load (Network)			-		-		-	
Short term firm Point-to-Point service:								
- Summerside	(average for 3 months)		10.0		10.0		10.0	
Non-firm Point-to-Point service:								
- Summerside	on-peak	(Jan, Feb and Dec)		8,613	8.3	(Appalachian)	8.3	(Appalachian)
	off-peak	(Jan, Feb and Dec)		2,921	1.4		1.4	
- West Cape wind	on-peak	(Jan, Feb and Dec)		49,380	22.9	(non-Appalachian)	47.5	(Appalachian)
	off-peak	(Jan, Feb and Dec)		40,946	19.0		19.0	
					281.4		306.0	

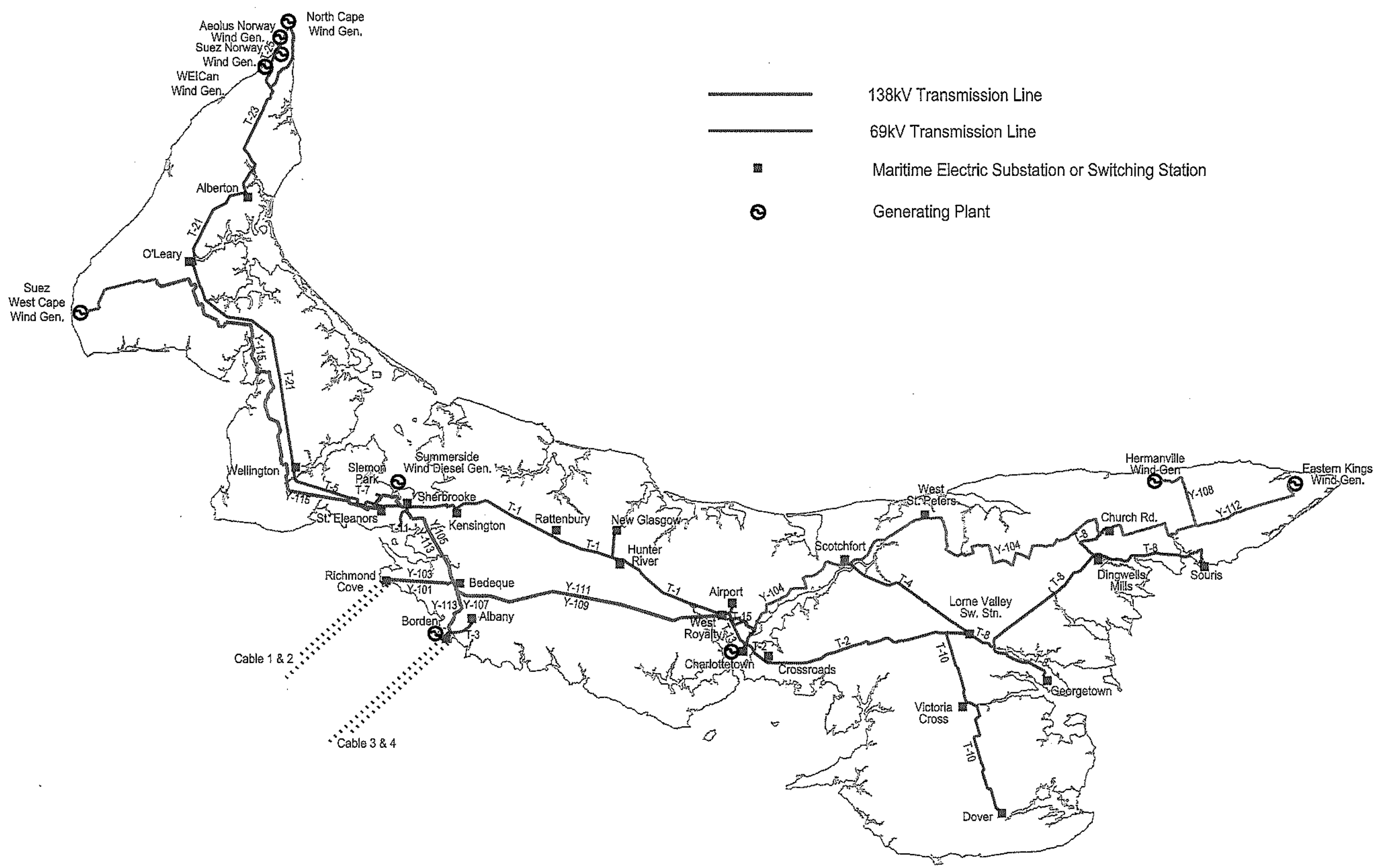
Note: Summerside stopped purchasing from West Cape in October 2014. Therefore all West Cape generation has been shown as exported for sale off-Island for 2014. Also, Summerside's on-peak non-firm Point-to-Point service quantity has been increased by the amount purchased from West Cape during on-peak in 2014.

B



MARTIME ELECTRIC
ENERGY SUPPLY SYSTEM
PRINCE EDWARD ISLAND

C



138kV Transmission Line
69kV Transmission Line
Maritime Electric Substation or Switching Station
Generating Plant
North Cape Wind Gen.
Aeolus Norway Wind Gen.
Suez Norway Wind Gen.
WEICan Wind Gen.
Suez West Cape Wind Gen.
Alberton
O'Leary
Wellington
Slemon Park
Summerside Wind Diesel Gen.
Sherbrooke
St. Eleanors
Kensington
Rattenbury
New Glasgow
Hunter River
Richmond Cove
Bedeque
Albany
Borden
Cable 1 & 2
Cable 3 & 4
Airport
West Royalty
Charlottetown
Crossroads
Scotchfort
West St. Peters
Lorne Valley Sw. Stn.
Victoria Cross
Dover
Georgetown
Dingwells Mills
Church Rd.
Souris
Hermanville Wind Gen
Eastern Kings Wind Gen.
T-23
T-21
Y-115
T-5
T-7
T-11
Y-105
Y-113
Y-103
Y-101
Y-107
T-3
T-1
Y-111
Y-109
T-15
Y-104
T-2
T-4
T-8
T-10
Y-108
Y-112

D

Coincident peak loads
16-12-08

2013 PEI MONTHLY COINCIDENT PEAK LOADS

2013 PEI MONTHLY COINCIDENT PEAK LOADS

					Summerside portion			Summerside transmission usage		
2013	Date	Hour ending	PEI peak load (MW)	Maritime Electric portion (MW)	Purchases (MW)	Generation (MW)	Total (MW)	Firm PT-to-Pt (MW)	Non-firm PT-to-Pt (MW)	Total (MW)
Jan	23	19:00	242.5	217.0	16.4	9.1	25.5	10.0	6.4	16.4
Feb	7	19:00	240.0	215.1	19.1	5.8	24.9	10.0	9.1	19.1
Mar	18	10:00	200.5	179.0	10.3	11.2	21.5	10.0	0.3	10.3
Apr	1	17:00	185.5	165.4	8.4	11.7	20.1	10.0	-	8.4
May	18	12:00	173.6	156.9	4.9	11.8	16.7	10.0	-	4.9
Jun	25	12:00	183.4	164.2	18.5	0.7	19.2	10.0	8.5	18.5
Jul	15	18:00	195.6	176.0	19.1	0.5	19.6	10.0	9.1	19.1
Aug	21	18:00	186.0	168.3	12.1	5.6	17.7	10.0	2.1	12.1
Sep	3	13:00	178.9	161.1	8.6	9.2	17.8	10.0	-	8.6
Oct	30	20:00	188.9	170.2	15.2	3.5	18.7	10.0	5.2	15.2
Nov	25	18:00	227.1	204.0	17.2	5.9	23.1	10.0	7.2	17.2
Dec	12	18:00	251.8	225.9	22.1	3.8	25.9	10.0	12.1	22.1
			Average	183.6						

Coincident peak loads
16-12-08

2014 PEI MONTHLY COINCIDENT PEAK LOADS

2014 PEI MONTHLY COINCIDENT PEAK LOADS

2014	Date	Hour ending	PEI peak load (MW)	Maritime Electric portion (MW)	Summerside portion			Summerside transmission usage		
					Purchases (MW)	Generation (MW)	Total (MW)	Firm PT-to-Pt (MW)	Non-firm PT-to-Pt (MW)	Total (MW)
Jan	3	18:00	243.8	218.9	13.7	11.2	24.9	10.0	3.7	13.7
Feb	6	20:00	236.9	213.6	19.3	4.0	23.3	10.0	9.3	19.3
Mar	5	20:00	225.4	202.0	21.4	2.0	23.4	10.0	11.4	21.4
Apr	24	17:00	196.4	175.5	10.7	10.2	20.9	10.0	0.7	10.7
May	5	18:00	189.4	171.9	7.0	10.5	17.5	10.0	-	7.0
Jun	30	17:00	181.0	162.4	16.7	1.9	18.6	10.0	6.7	16.7
Jul	4	12:00	194.1	174.5	10.7	8.9	19.6	10.0	0.7	10.7
Aug	5	18:00	195.0	176.8	18.0	0.2	18.2	10.0	8.0	18.0
Sep	3	12:00	184.9	166.4	11.4	7.1	18.5	10.0	1.4	11.4
Oct	27	19:00	195.6	177.2	11.9	6.5	18.4	10.0	1.9	11.9
Nov	27	18:00	225.0	202.1	15.3	7.6	22.9	10.0	5.3	15.3
Dec	30	18:00	254.5	227.1	23.5	3.9	27.4	10.0	13.5	23.5
			Average	189.0						

Coincident peak loads
16-12-08

2015 PEI MONTHLY COINCIDENT PEAK LOADS

2015 PEI MONTHLY COINCIDENT PEAK LOADS

					Summerside portion			Summerside transmission usage		
2015	Date	Hour ending	PEI peak load (MW)	Maritime Electric portion (MW)	Purchases (MW)	Generation (MW)	Total (MW)	Firm PT-to-Pt (MW)	Non-firm PT-to-Pt (MW)	Total (MW)
Jan	6	18:00	263.9	235.3	26.2	2.4	28.6	10.0	16.2	26.2
Feb	2	18:00	254.1	229.1	24.3	0.7	25.0	10.0	14.3	24.3
Mar	6	20:00	232.5	207.7	21.4	3.4	24.8	10.0	11.4	21.4
Apr	10	11:00	198.4	176.2	16.4	5.8	22.2	10.0	6.4	16.4
May	12	12:00	183.5	164.8	8.7	10.0	18.7	10.0	-	8.7
Jun	3	18:00	182.7	165.0	8.3	9.4	17.7	10.0	-	8.3
Jul	31	12:00	189.6	171.0	16.8	1.8	18.6	10.0	6.8	16.8
Aug	19	17:00	204.9	183.8	20.2	0.9	21.1	10.0	10.2	20.2
Sep	7	21:00	182.6	165.8	7.4	9.4	16.8	10.0	-	7.4
Oct	19	20:00	193.0	173.0	20.0	-	20.0	10.0	10.0	20.0
Nov	30	18:00	235.2	210.5	21.7	3.0	24.7	10.0	11.7	21.7
Dec	28	18:00	240.6	215.1	17.9	7.6	25.5	10.0	7.9	17.9
			Average	191.4						

E

RESPONSES TO QUESTIONS IN A DECEMBER 7, 2016 E-MAIL FROM RYAN MacDONALD ON BEHALF OF THE CITY OF SUMMERSIDE

Question 1:

Can you provide an indication as to the margins that you believe Suez may be achieving? There was reference to the "back of an envelope" calculation, but if an indication as to the range of margin can be provided, it would be appreciated.

Response:

It would be inappropriate for Maritime Electric to provide a number. The City can always contact Suez directly.

Question 2:

Can you provide the coincident peak load on the electricity transmission system for each month over the last three years (36 months), including the values for the twelve month period used in MECL's recent transmission tariff application (i.e. 2014)? For each monthly peak value, can you also indicate the following:

'(a) Hour in which the peak load occurs.

'(b) A breakdown of each of the components of the monthly peak demand, including:

'(i) Demand by Maritime Electric's own customer base,

'(ii) Other users of Network Service (if any),

'(iii) Firm Point to Point (PTP) reservations, and

'(iv) Any other demand contributing to the demand peak.

Response:

The following are also provided separately in an Excel workbook.

2013 PEI MONTHLY COINCIDENT PEAK LOADS

2013	Date	Hour ending	PEI peak load (MW)	Maritime Electric portion (MW)	Summerside portion: Purchases (MW)	Summerside portion: Generation (MW)	Summerside portion: Total (MW)	Summerside transmission usage: Firm PT-to-Pt (MW)	Summerside transmission usage: Non-firm PT-to-Pt (MW)	Summerside transmission usage: Total (MW)
Jan	23	19:00	242.5	217.0	16.4	9.1	25.5	10.0	6.4	16.4
Feb	7	19:00	240.0	215.1	19.1	5.8	24.9	10.0	9.1	19.1
Mar	18	10:00	200.5	179.0	10.3	11.2	21.5	10.0	0.3	10.3
Apr	1	17:00	185.5	165.4	8.4	11.7	20.1	10.0	-	8.4
May	18	12:00	173.6	156.9	4.9	11.8	16.7	10.0	-	4.9
Jun	25	12:00	183.4	164.2	18.5	0.7	19.2	10.0	8.5	18.5
Jul	15	18:00	195.6	176.0	19.1	0.5	19.6	10.0	9.1	19.1
Aug	21	18:00	186.0	168.3	12.1	5.6	17.7	10.0	2.1	12.1
Sep	3	13:00	178.9	161.1	8.6	9.2	17.8	10.0	-	8.6
Oct	30	20:00	188.9	170.2	15.2	3.5	18.7	10.0	5.2	15.2
Nov	25	18:00	227.1	204.0	17.2	5.9	23.1	10.0	7.2	17.2
Dec	12	18:00	251.8	225.9	22.1	3.8	25.9	10.0	12.1	22.1
			Average	183.6						

2014 PEI MONTHLY COINCIDENT PEAK LOADS

2014	Date	Hour ending	PEI peak load (MW)	Maritime Electric portion (MW)	Summerside portion Purchases (MW)	Summerside portion Generation (MW)	Summerside portion Total (MW)	Summerside transmission usage Firm PT-to-Pt (MW)	Summerside transmission usage Non-firm PT-to-Pt (MW)	Summerside transmission usage Total (MW)
Jan	3	18:00	243.8	218.9	13.7	11.2	24.9	10.0	3.7	13.7
Feb	6	20:00	236.9	213.6	19.3	4.0	23.3	10.0	9.3	19.3
Mar	5	20:00	225.4	202.0	21.4	2.0	23.4	10.0	11.4	21.4
Apr	24	17:00	196.4	175.5	10.7	10.2	20.9	10.0	0.7	10.7
May	5	18:00	189.4	171.9	7.0	10.5	17.5	10.0	-	7.0
Jun	30	17:00	181.0	162.4	16.7	1.9	18.6	10.0	6.7	16.7
Jul	4	12:00	194.1	174.5	10.7	8.9	19.6	10.0	0.7	10.7
Aug	5	18:00	195.0	176.8	18.0	0.2	18.2	10.0	8.0	18.0
Sep	3	12:00	184.9	166.4	11.4	7.1	18.5	10.0	1.4	11.4
Oct	27	19:00	195.6	177.2	11.9	6.5	18.4	10.0	1.9	11.9
Nov	27	18:00	225.0	202.1	15.3	7.6	22.9	10.0	5.3	15.3
Dec	30	18:00	254.5	227.1	23.5	3.9	27.4	10.0	13.5	23.5
			Average	189.0						

2015 PEI MONTHLY COINCIDENT PEAK LOADS

2015	Date	Hour ending	PEI peak load (MW)	Maritime Electric portion (MW)	Summerside portion Purchases (MW)	Summerside portion Generation (MW)	Summerside portion Total (MW)	Summerside transmission usage Firm PT-to-Pt (MW)	Summerside transmission usage Non-firm PT-to-Pt (MW)	Summerside transmission usage Total (MW)
Jan	6	18:00	263.9	235.3	26.2	2.4	28.6	10.0	16.2	26.2
Feb	2	18:00	254.1	229.1	24.3	0.7	25.0	10.0	14.3	24.3
Mar	6	20:00	232.5	207.7	21.4	3.4	24.8	10.0	11.4	21.4
Apr	10	11:00	198.4	176.2	16.4	5.8	22.2	10.0	6.4	16.4
May	12	12:00	183.5	164.8	8.7	10.0	18.7	10.0	-	8.7
Jun	3	18:00	182.7	165.0	8.3	9.4	17.7	10.0	-	8.3
Jul	31	12:00	189.6	171.0	16.8	1.8	18.6	10.0	6.8	16.8
Aug	19	17:00	204.9	183.8	20.2	0.9	21.1	10.0	10.2	20.2
Sep	7	21:00	182.6	165.8	7.4	9.4	16.8	10.0	-	7.4
Oct	19	20:00	193.0	173.0	20.0	-	20.0	10.0	10.0	20.0
Nov	30	18:00	235.2	210.5	21.7	3.0	24.7	10.0	11.7	21.7
Dec	28	18:00	240.6	215.1	17.9	7.6	25.5	10.0	7.9	17.9
			Average	191.4						

Question 3:

Wind generators are excluded from the third tier band of penalties on the Energy Imbalance service Schedule 4. Based on the fact that Summerside has embedded wind generation that affects it scheduling, how does MECL propose to deal with Summerside's energy imbalance due to forecasting errors?

Response:

Summerside's energy imbalance will be treated in the same way as Maritime Electric's energy imbalance – the exemption from the third tier penalty band will not apply.

What both Summerside and Maritime Electric schedule for is delivery of energy purchases from NB Power at the interconnection point at Murray Corner, New Brunswick. For both the City and MECL, the amount scheduled at Murray Corner is the respective load forecast for the hour minus the respective forecast of wind generation for the hour. Thus, from the perspective of Murray Corner, the respective wind generation for both the City and MECL is "embedded", and the exemption from the third band of imbalance penalties does not apply. (The wind generation that Maritime Electric purchases from the PEI Energy Corporation's wind farms is effectively embedded because MECL takes Network Service, and thus does not schedule transmission service for individual delivery from each of the wind farms)

An example of where the exemption does apply is for scheduled delivery of wind generation; e.g. generation at the West Cape wind farm being exported to New Brunswick. The exemption would also apply to delivery of Summerside wind generation to Murray Corner.

Question 4:

How and where are the monies collected through the imposition of penalties for the energy imbalance service going to applied?

Response:

The collection of imbalance penalties will be through month-end billings by the OATT Administrator.

Question 5:

If there is any accrual of funds from these penalties how will the accrual be refunded to users of the system?

Response:

Maritime Electric proposes that revenue from imbalance penalties will be accrued through the year. At year end the accrued revenue will be used to reduce the rates for Network and Point-to-Point transmission service effective February 1 of the following year.

Question 6:

What is the methodology behind the level of penalties chosen and the bands?

Response:

As explained in pages 29 to 32 (starting on page 66 of the filed Adobe document) of W.K. Marshall's Evidence that makes up part of Maritime Electric's filing, the imbalance penalty percentage levels and the bands in MECL's proposed OATT are those adopted by the Federal Energy Regulatory Commission in its Order 890. MECL believes they are reasonable, and the Company has not done any investigation into how they were developed.

Question 7:

Can you provide a one line diagram of the MECL 69 kV and 138 kV grid, both before and after completion of line Y-104?

Response:

The requested one-line diagrams are provided as separate attachments.

In anticipation of the follow up question that the City will ask, Maritime Electric is also providing the following:

The Y-104 transmission line project, including the Church Road Substation, has an estimated cost of $ 14.5 million, of which $ 11.0 million is for the line itself and $ 3.5 million is for the Church Road Substation and the 138 kV breaker and associated equipment at the West Royalty Substation end of the line.

If there was no wind generation at the PEI Energy Corporation's Eastern Kings and Hermanville wind farms, the 69 kV transmission line T-4 would probably have been rebuilt at 138 kV and the 138 kV / 69 kV transformer at Church Road would have been installed at the Lorne Valley Station instead.

Line Y-104 is 82.5 km long, whereas T-4 is 43.1 km long. The extra 39.4 km for Y-104 represents $ 5.2 million on a pro rata basis, and MECL's intention is that this $ 5.2 million will be included with the designated transmission facilities associated with wind farms serving only MECL load for OATT purposes. The $ 9.3 million for Y-104 that MECL will propose to be included in the OATT revenue requirement will result in an estimated 14 % increase in Network and Point-to-Point transmission service charges, probably starting in 2019.

The above numbers are estimates, and their purpose is to provide an indication of the impact of the Y-104 project on the OATT revenue requirement.

F

INDUSTRIAL BYPASS PROVISION IN ATTACHMENT K IS NOT APPLICABLE TO SUMMERSIDE

This summarizes Maritime Electric's determination that 'industrial' bypass is not applicable to the City of Summerside.

Summerside's question regarding the applicability of 'industrial bypass rate' to the City refers to the filed OATT Attachment K, Section 5.7 ('Industrial Expansion System Bypass Policy'). The first sentence of this section states "This policy pertains to situations where a customer proposes to serve new load using new on-site generation by wheeling through the local portion of the Transmission System."

There are instances in North America where an electricity 'bypass' or 'avoidance tariff' exemption has been granted if the proponent meets fairly stringent requirements. In reviewing various jurisdictions, the exemptions are not intended to facilitate development of independent electricity systems driven by avoidance of system costs. They are in place to provide the correct economic signals which enable industrial processes to develop their own internal electricity supply (assuming it is the most economic generation source) and distribute it to their on-site load.

In Alberta, for example, the following requirements need to be met in order for a 'bypass' or 'avoidance tariff' exemption to be considered:

- The industrial system involves integrated industrial processes using shared equipment and continuous product flow;
- Facilities are interconnected by substantial items of common site infrastructure;
- Facilities must be contiguous, although may be separated by a public roadway;
- The integrated operations must produce or manufacture end products in order to be eligible to be designated as an industrial system;
- Process linkages based only on electric or thermal energy supply are insufficient to define an integrated process;
- There must be common ownership of facilities; and
- The generation is considered 'self-generation', and is thus located 'behind the fence'.

In addition, the proponent has to demonstrate that it is less expensive to build on-site transmission/distribution infrastructure from its on-site generation to on-site load than to use the neighbouring transmission system. If these conditions are met, a 'bypass' or 'avoidance tariff' is considered, whereby the proponent uses the existing transmission system, and pays to the transmission system the same amount that it would to build and operate its own on-site system. The customer is kept cost-neutral, and there is increased traffic on the existing transmission system, which lowers unit costs for all transmission system users. Research into US systems reveal policies very similar to Alberta's in certain jurisdictions.

Ontario has provisions in its Transmission Code regarding bypass and bypass compensation, however these refer to situations where:

- A customer disconnects its facility from the transmitter's connection facilities, and subsequently connects its facilities to its own connection or to connection facilities own by another person (other than the transmitter);
- A customer transfers load from the transmitter's connection facilities to its own connection facilities; or
- An existing generation facility, for which transmission assets were built, is reconfigured and connects onto another customer's connection.

In the first two cases, the connection point is different, but the transmission system sees the same amount of energy flow. The customer would still have the same transmission service bill; the 'bypass compensation' is paid to the transmitter to compensate the transmitter for stranded capital costs of its bypassed facilities. The 'bypass compensation' in the last case also refers to the stranded transmitter assets, presumably for facilities built to supply the generator, and does not specifically refer to transmission service. There is no mention of a electricity 'bypass' per se, where a customer can build duplicate facilities to avoid the transmission system, nor is there a 'bypass rate' concept.

In summary, there does not appear to be any precedent in North America where off-site generation was granted 'bypass' status to supply on-site load; rather the postage stamp philosophy sets the transmission service rate for use of the transmission system.

Sherri Quinn Jewell

From: Spencer Campbell <scampbell@stewartmckelvey.com>
Sent: Thursday, December 15, 2016 10:25 AM
To: Ryan MacDonald
Cc: Derek Key; Jeff Cormier
Subject: FERC tests for 12CP - Summerside questions
Attachments: CP tests FERC 20130815123655-ER06-274-007.pdf

Ryan further to my last email, please see additional information attached and the following commentary from Bob Younker.

Spencer:

The attached Adobe document is a FERC order in which the tests for appropriateness of using 12CP are described (starting on page 20).

I think that the FERC tests are intended to help find an appropriate balance between the "cost causation" and the "used and useful" principles in ratemaking. The investment in the transmission system is a function of the annual peak load (cost causation), but the transmission system is used and useful year round. If the annual peak is not significantly larger than the monthly peak loads during the rest of the year, then 12CP is appropriate because it better reflects the year round used and useful nature of the system. If the annual peak is significantly larger than the non-Winter monthly peaks, then 3CP (average of Jan, Feb and Dec) would better reflect the cost causation impact of the annual peak. The FERC tests are intended to quantify "significantly".

(The FERC order refers to 4CP as the alternative to 12CP because it is concerned with a Summer peaking system, with Jun – Sep as the potential peak months.)

The results of the FERC tests are marginally in favour of 12CP, which is what MECL's OATT filing is based on.

A comparison of demand determinants based on 12CP versus 3CP shows little difference – both approaches allocate 7.0 % of the transmission system cost to Summerside. Given a choice, MECL would not want to use 3CP because I think that the billing would be more difficult.

Bob

A

144 FERC ¶ 61,133
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony Clark.

Southwestern Public Service Company Docket No. ER06-274-007

ORDER ON INITIAL DECISION

(Issued August 15, 2013)

1. On December 1, 2005, Southwestern Public Service Company (SPS) filed, pursuant to section 205 of the Federal Power Act (FPA),[1] revisions to the rates and rate design applicable to SPS's full and partial requirements customers. On August 29, 2008, the presiding Administrative Law Judge (Presiding Judge) issued an Initial Decision granting SPS's motion for summary disposition on the sole remaining issue in the proceeding: the appropriate demand cost allocation methodology for the SPS system during the period from July 1, 2006 to June 30, 2008 (Locked-In Period).[2] Golden Spread Electric Cooperative, Inc. (Golden Spread) filed a brief on exceptions, and SPS, Cap Rock Energy Corporation (Cap Rock), Commission Trial Staff (Trial Staff), and the New Mexico Cooperatives[3] opposed Golden Spread's exceptions. In this order, we reverse the Initial Decision and determine the appropriate demand cost allocation methodology for the Locked-In Period.[4]

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[1] 16 U.S.C. § 824d (2006).

[2] *Southwestern Pub. Serv. Co.*, 124 FERC ¶ 63,015 (2008) (Initial Decision).

[3] For the purposes of this order, the New Mexico Cooperatives are Farmers Electric Cooperative, Inc.; Lea County Electric Cooperative, Inc.; Central Valley Electric Cooperative, Inc.; and Roosevelt County Electric Cooperative, Inc.

[4] Our determination on SPS's demand cost allocator in this order will apply beyond the Locked-In Period for Golden Spread. Unlike other parties in this proceeding, Golden Spread's rates are not at issue in SPS's subsequent rate case, Docket No. ER08-749-000. Therefore, the demand allocator established for SPS in the instant proceeding will apply to SPS's partial requirements customers, including Golden Spread, until SPS

(continued...)

I. Background

2. Demand cost allocation, or demand allocation, refers to the method by which a utility apportions fixed capacity costs among customer classes. The Commission typically allocates demand costs using a coincident peak method, through which demand costs are allocated based on each customer class's load at the time of (or coincident with) the system peak load. The coincident peak may be based, for example, on a single peak month (1 CP), the average of three peak months (3 CP), or the average of peaks in 12 months (12 CP). Typically, a company that has a relatively flat load profile throughout the year would allocate demand costs on a 12 CP basis, which assumes that a utility's load is relatively constant throughout all 12 months of the year. A summer (or winter) peaking company would allocate demand costs more typically on a 3 CP basis, which assumes the load profile peaks during three peak usage months.

3. The Initial Decision's analysis of the appropriate demand cost allocator for the SPS system depends not just on the instant rate case, but also on SPS's rate cases immediately preceding and following the instant rate case. The background on each of these three closely related SPS proceedings is presented in the following order: Docket No. ER06-274-000 (the instant rate case), the Opinion No. 501 proceeding (the SPS rate case preceding this one),[5] and Docket No. ER08-749-000 (the SPS rate case subsequent to this one).[6]

A. ER06-274-000 Proceeding

4. On December 1, 2005, SPS filed revisions to its wholesale full and partial requirements customers' rates and rate design.[7] On January 31, 2006, the Commission conditionally accepted SPS's proposed revisions for filing, suspended the rates to become effective on July 1, 2006, subject to refund, and set the matter for hearing in Docket

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seeks to change the demand cost allocator for its partial requirements customers. Nonetheless, for the sake of simplicity, we will refer to the refund period in the instant proceeding as the Locked-In Period.

[5] *See generally Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co.*, Opinion No. 501, 123 FERC ¶ 61,047, at 61,249 (2008).

[6] *See generally Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,225 (2008) (Docket No. ER08-749-000 Hearing Order).

[7] SPS Dec. 1, 2005 Rate Filing.

No. ER06-274-000.[8] The Commission held the hearing in abeyance pending the outcome of settlement judge procedures.[9]

5. Settlement negotiations were conducted throughout the first half of 2006 and ultimately yielded two settlement agreements: (1) a partial settlement among SPS and its full requirements customers, i.e., the New Mexico Cooperatives and Cap Rock, (Full Requirements Settlement Agreement),[10] and (2) a partial settlement between SPS and the Public Service Company of New Mexico (PNM) (PNM Settlement Agreement).[11] The Full Requirements Settlement Agreement was approved by the Commission on September 20, 2007.[12] The PNM Settlement Agreement was approved by the Commission on September 8, 2008.[13]

6. The Full Requirements Settlement Agreement resolved all issues in Docket No. ER06-274 among SPS, the New Mexico Cooperatives, and Cap Rock, but it reserved those parties' rights to continue litigating the demand allocation issue.[14] The PNM Settlement Agreement resolved, going forward, all issues in Docket No. ER06-274-007 regarding rates charged by SPS to PNM pursuant to their interruptible power service agreement.[15] Under the PNM Settlement Agreement, the rates SPS charged PNM from

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[8] *Southwestern Pub. Serv. Co.*, 114 FERC ¶ 61,091 (2006) (Hearing Order).

[9] *Id.* P 20.

[10] SPS Sept. 7, 2006 Offer of Settlement, *approved in Southwestern Pub. Serv. Co.*, 120 FERC ¶ 61,243 (2007).

[11] SPS Sept. 19, 2006 Offer of Settlement, *approved in Southwestern Pub. Serv. Co.*, 124 FERC ¶ 61,232 (2008).

[12] *Southwestern Pub. Serv. Co.*, 120 FERC ¶ 61,243 (2007).

[13] *Southwestern Pub. Serv. Co.*, 124 FERC ¶ 61,232 (2008).

[14] *Southwestern Pub. Serv. Co.*, 120 FERC ¶ 61,243 at P 18.

[15] *Id.* P 33. The PNM Settlement Agreement also resolved all issues in Docket No. EL05-151-000 except the issues pertaining to SPS's fuel cost adjustment clause. *Id.*

July 1, 2006 until the wholesale partial requirements rates are determined in Docket No. ER06-274-007 are subject to refund.[16]

7. SPS was initially unable to reach a negotiated settlement with one of its partial requirements customers, Golden Spread, and one of its retail customers, Occidental Permian, Ltd. (Occidental). Accordingly, on August 2, 2006, Golden Spread and Occidental were severed from the settlement proceeding in Docket No. ER06-274-000, and hearing procedures were initiated in Docket No. ER06-274-003. The parties submitted testimony in the proceeding; however, the hearing procedures were again suspended on March 29, 2007 to allow the participants to resume settlement negotiations. On December 3, 2007, that round of settlement negotiations resulted in a settlement (December 2007 Settlement Agreement) among SPS, Golden Spread, and Occidental that resolved all issues among those three parties except for the appropriate demand cost allocator methodology for the SPS system.[17] Accordingly, on February 5, 2008, hearing procedures were reinitiated in Docket No. ER06-274-007 to determine the appropriate demand cost allocator for the Locked-In Period.

8. On February 19, 2008, the Presiding Judge issued an Order Establishing Procedural Schedule (Scheduling Order).[18] The Presiding Judge noted the parties' statement, in the December 2007 Settlement Agreement, that the case could be promptly litigated due to the posture of the case with respect to the demand cost allocation issue. The settlement offer stipulated that discovery had ended and that initial, answering, and rebuttal testimony had been filed on the issue of the proper demand cost allocator methodology prior to the suspension of the procedural schedule in that proceeding. Therefore, the Presiding Judge ordered the participants to resubmit the testimony proffered in Docket No. ER06-274-003, after redacting all testimony not dealing with the demand cost allocator issue.

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[16] *Southwestern Pub. Serv. Co.*, 124 FERC ¶ 61,232 at P 5. Under section II.B.3 of the PNM Settlement Agreement, SPS is required to submit a compliance filing within 30 days of the date on which the wholesale partial requirements rates are determined in the instant docket. *Id.* P 6.

[17] The Commission approved the December 2007 Settlement Agreement on April 21, 2008. *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,054 (2008).

[18] *Southwestern Pub. Serv. Co.*, Docket No. ER06-274-007 (Feb. 19, 2008).

9. In total, the parties submitted testimony from five witnesses on the demand cost allocation issue and that testimony included detailed load data for the SPS system.[19] Much of the testimony focused on the results of the three separate peak load tests, explained in detail below, that the Commission has traditionally used to determine the appropriate demand cost allocator for a utility. In short, the witnesses for SPS and the New Mexico Cooperatives testified that all three peak load tests indicate that a 12 CP demand allocator is appropriate, while Golden Spread's witness testified that one of the tests indicates that SPS is a 3 CP utility and the other two tests produce "borderline" 12 CP results but are very close to the results these tests produced in Opinion No. 162, the 1983 rate case in which the Commission initially found SPS to be a 3 CP utility.[20] A key difference between the witnesses' test results was the treatment of SPS's sales to El Paso Electric Company (EPE) and PNM. SPS's witnesses included the sales to EPE and PNM in their load calculations, whereas Golden Spread's witnesses excluded those sales.

10. On June 12, 2008, SPS filed a motion for summary disposition on the appropriate demand cost allocator methodology for the Locked-In Period.[21] The Presiding Judge initially denied SPS's motion after erroneously construing it as a motion to dismiss.[22] SPS filed a motion for reconsideration of that decision, which the Presiding Judge granted on June 18, 2008.

11. In the motion for summary disposition, SPS argued, in pertinent part, that the Commission had determined in the rate cases immediately before and after the Locked-In Period—Opinion No. 501 and Docket No. ER08-749-000, respectively—that SPS was a 12 CP utility, and that the three peak load tests support the same determination for the Locked-In Period.[23] SPS also replicated a table that the Commission used in Opinion

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[19] In analyzing SPS's load characteristics for the Locked-In Period, the witnesses used 2005-2006 data. However, the parties used actual data for certain months and projected data for the other months of the year. To compute the projected data, some of the parties used SPS's historical data from years 2000-2006. In analyzing demand allocation, the Commission typically uses data from more than one year to account for anomalous demand that may occur due to unseasonable weather or unusual system conditions.

[20] Ex. GSE-40 at 11.

[21] SPS June 12, 2008 Motion for Summary Disposition.

[22] *Southwestern Pub. Serv. Co.*, Docket No. ER06-274-007 (Jun. 13, 2008).

[23] SPS June 12, 2008 Motion for Summary Disposition at 4.

No. 501 to illustrate the results of the peak load tests, but SPS expanded upon that table by including the results of each witness in the instant proceeding.[24]

12. Cap Rock, New Mexico Cooperatives, and Trial Staff all filed answers supporting SPS's motion for summary disposition. Golden Spread submitted an answer on July 3, 2008 opposing SPS's motion for summary disposition. Golden Spread's July 3, 2008 answer also included a cross-motion to hold the hearing in abeyance pending the outcome of rehearing requests on Opinion No. 501. SPS and Cap Rock filed answers opposing Golden Spread's motion to hold the case in abeyance on July 9, 2008 and July 18, 2008, respectively. As discussed below, the Presiding Judge issued the Initial Decision granting SPS's motion for summary disposition while Opinion No. 501 was still pending rehearing.[25] In granting the motion, the Presiding Judge relied, in part, on the Commission's determination in the immediately preceding SPS rate case, the Opinion No. 501 proceeding.

[24] The table from Opinion No. 501 and SPS's expanded version of that table are presented here:

Opinion No. 501 Chart	Lowest-To-Peak	On-Peak-Off-Peak	Average-To-Peak
Historical Commission Range for 12 CP	66% or higher	19% or less	81% or higher
Heintz, SPS-37 at 16	68%	19%	82%
Saffer FRC-2 Pro Forma	70%	18%	84%
Linxwiler, GSL – 1 at 9-1-10	67.55%	19%	82.05%
Diller, CRE-1 at 18	70%	18%	84%

Expanded Chart			
Hudson, SPS-4	68%	19%	83%
Heintz, SPS-63	69%	19%	83%
Saffer, NMC-2	70%	18%	84%
Linxwiler, GSE-50	68% - 69%	19% - 20%	82-83%

Id. at 6. As discussed in detail below, the data SPS presented from Mr. Linxwiler's testimony includes SPS's off-system sales to EPE and PNM, which Mr. Linxwiler argued should be excluded.

[25] Initial Decision, 124 FERC ¶ 63,015 (2008) (issued August 29, 2008).

B. Opinion No. 501 Proceeding

13. On November 2, 2004, just over one year before SPS commenced the instant proceeding, Golden Spread, Lyntegar Electric Cooperative, Inc. (Lyntegar), and the New Mexico Cooperatives, filed a complaint in Docket No. EL05-19-000 alleging that SPS was violating the Commission's fuel cost adjustment clause (FCAC) regulations and the FCAC provisions of its wholesale customers' rate schedules.[26] On the same day that the complaint was filed, SPS also filed, in Docket No. ER05-168-000, proposed revisions to its FCAC and power supply contracts, contending that such revisions were necessary to conform to the Commission's current fuel cost and purchased economic power adjustment clause regulations.[27] Docket Nos. EL05-19-000 and ER05-168-000 were subsequently consolidated and set for hearing.[28]

14. A hearing was conducted in Docket Nos. EL05-19-002 and ER05-168-001 at which SPS argued that a 12 CP demand allocator was appropriate for the locked-in period from January 1, 2005 through June 30, 2006, despite the fact that SPS had historically used a 3 CP demand allocator. On May 24, 2006, the Administrative Law Judge in that proceeding issued an initial decision ordering SPS to continue using a 3 CP demand allocation methodology.[29] Between July and November of 2007 the parties filed three motions requesting that the Commission withhold action on the initial decision pending the outcome of settlement discussions. The Commission granted the motions.

15. As mentioned above, on December 3, 2007, SPS filed the December 2007 Settlement Agreement on behalf of itself, Golden Spread, Lyntegar, and Occidental in Docket Nos. EL05-19-000, ER05-168-000, and ER06-274-000. The December 2007 Settlement Agreement resolved, among those four parties, all issues except the appropriate demand cost allocator for the SPS system. The Commission approved the December 2007 Settlement Agreement on April 21, 2008.[30]

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[26] Complaint, Docket No. EL05-19-000 (filed Nov. 2, 2004).

[27] SPS Tariff Filing, Docket No. ER05-168-000 (filed Nov. 2, 2004).

[28] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004) (Opinion No. 501 Hearing Order).

[29] *Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co.*, 115 FERC ¶ 63,043, at 65,174 (2006).

[30] *Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,054 (2008).

16. Also on April 21, 2008, the Commission issued its order on initial decision – Opinion No. 501– in which it overruled the Administrative Law Judge on the issue of the appropriate demand cost allocator.[31] The Commission found that SPS demonstrated load profile changes warranting a determination that a 12 CP demand allocation methodology was appropriate for the locked-in period in that proceeding. Several parties filed requests for rehearing and clarification of Opinion No. 501.

17. Between June 2009 and June 2010, the parties submitted 10 motions requesting that the Commission defer action on the requests to accommodate the ongoing settlement negotiations in the Opinion No. 501 proceeding. Those settlement negotiations yielded two additional settlement agreements in January 2010 and July 2010 that resolved all issues in the Opinion No. 501 proceeding among SPS, Occidental, Cap Rock, and the New Mexico Cooperatives. Concurrent with the instant order, the Commission, in a separate order, grants in part and denies in part the remaining requests for rehearing and clarification of Opinion No. 501.[32] However, as mentioned above, the Presiding Judge in the instant proceeding issued the Initial Decision while the rehearing requests were pending in the Opinion No. 501 proceeding.

C. **ER08-749-000 Proceeding**

18. In addition to the Opinion No. 501 proceeding, the Initial Decision also relied upon the Commission's determination on the demand cost allocation issue in the SPS rate case immediately following the instant rate case. On March 31, 2008, almost five months before the Presiding Judge issued the Initial Decision in the instant proceeding, SPS filed additional changes to the rates and rate design applicable to its wholesale full requirements customers.[33] SPS filed the rates using a 3 CP demand cost allocator, but agreed to use a 12 CP demand cost allocator, instead, if the Commission suspended the rates for only a nominal period.[34] On May 30, 2008, the Commission conditionally accepted SPS's proposed rates for filing using the 12 CP demand cost allocator, suspended the rates for a nominal period, to become effective June 1, 2008, subject to

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[31] *Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co.*, Opinion No. 501, 123 FERC ¶ 61,047, at 61,249 (2008).

[32] *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*, Opinion No. 501-A, 144 FERC ¶ 61,132 (2013).

[33] SPS, Transmittal, Docket No. ER08-749-000 (filed Mar. 31, 2008).

[34] *Id.* at 4-5.

refund, and established hearing and settlement judge procedures in Docket No. ER08-749-000.[35]

II. Substantive Matters

A. Initial Decision

19. On August 29, 2008, the Presiding Judge granted SPS's motion for summary disposition in the instant proceeding, finding that there was no genuine issue of material fact in dispute. The Presiding Judge found that, based on the record as a whole, it was reasonable to conclude that a 12 CP demand allocation methodology was appropriate for the Locked-In Period.

20. The Presiding Judge explained that the Commission had found, "on essentially the same evidence in this case," that a 12 CP demand allocator was appropriate for the SPS system immediately before and after the Locked-In Period, in Opinion No. 501 and Docket No. ER08-749-000. The Presiding Judge explained that the doctrine of the law of the case precludes a lower decisional authority from reconsidering an issue already decided by a higher decisional authority and that the doctrine applied under these circumstances. Accordingly, the Presiding Judge concluded that the Commission had already found that the 12 CP demand cost allocator was appropriate for SPS.

21. The Presiding Judge found SPS's expanded version of the Opinion No. 501 peak load test table to be "an especially important piece of evidence in this case." The Presiding Judge explained that the Commission used the same analytical criteria for the table in Opinion No. 501 that it used in earlier proceedings – Opinion Nos. 162[36] and 337[37] – in which the Commission found a 3 CP demand allocator to be appropriate for SPS. The Presiding Judge explained that SPS's expanded table, which applied the same analytical criteria from Opinion No. 501 to the evidence submitted in this case, shows that SPS has continued to be a 12 CP utility since the locked-in period in Opinion No. 501.

22. The Presiding Judge rejected Golden Spread's argument that the relevance of Opinion No. 501 is lessened by the fact that it does not take into account evidence of

[35] Docket No. ER08-749-000 Hearing Order, 123 FERC ¶ 61,225.

[36] *Southwestern Pub. Serv. Co.*, Opinion No. 162, 22 FERC ¶ 61,341 (1983).

[37] *Southwestern Pub. Serv. Co.*, Opinion No. 337, 49 FERC ¶ 61,296 (1989), *reh'g denied*, Opinion No. 337-A, 51 FERC ¶ 61,341 (1990) (Opinion No. 337) (affirming the ALJ's decision that SPS remained a 3 CP utility).

recent changes on the SPS system. The Presiding Judge explained that, to the extent Golden Spread was referring to evidence more recent than the parties' written filings in this proceeding, Golden Spread's argument was unavailing. The Presiding Judge stated that, after Golden Spread had agreed in the December 2007 Settlement Agreement that discovery had ended, the written testimony had been re-filed and that testimony contained nothing that lessened the relevance of Opinion No. 501.

23. The Presiding Judge also rejected Golden Spread's argument that the elapsed time between the test periods in Opinion No. 501 and the instant proceeding supports denying SPS's motion for summary disposition. The Presiding Judge explained that unlike in *Illinois Power*,[38] where the test periods were four years apart, the test periods in Opinion No. 501 and the instant proceeding are closer in time – two years apart. The Presiding Judge explained further that Golden Spread had the opportunity to submit more recent data in this proceeding than it submitted in the Opinion No. 501 proceeding, and the new data does not show that anything "extraordinary" happened during the Locked-In Period that would render the determinations in Opinion No. 501 less controlling. The Presiding Judge concluded that no genuine issue of material fact existed and that the record, taken as a whole, led to the reasonable conclusion that SPS was a 12 CP utility for the Locked-In Period.

B. Briefs

1. Briefs on Exceptions

24. Golden Spread excepts to the Initial Decision based on four alleged legal errors and their associated policy considerations.[39]

25. First, Golden Spread argues that the Initial Decision misapplies the doctrine of the law of the case. According to Golden Spread, that doctrine serves only to preclude reconsideration of "the *same issue* in the *same case* by the *same court*."[40] Golden Spread argues that the Initial Decision improperly expands the doctrine by concluding that the resolution of the same issue in a different case must lead to the same result on that issue

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[38] *Illinois Power Co.*, 59 FPC 2245 (1977), *reh'g denied*, 1 FERC ¶ 61,174 (1977).

[39] Golden Spread Sept. 29, 2008 Brief on Exceptions at 6.

[40] *Id.* at 11 (emphasis in original) (citing *Williamsburg Wax Museum, Inc. v. Historic Figures, Inc.*, 810 F.2d 243, 250 (D.C. Cir. 1987); *Kimberlin v. Quinlan*, 199 F.3d 496, 500 (D.C. Cir. 1999); *Florida Gas Transmission Co.*, 41 FERC ¶ 61,122, at 61,302 n.10-11 (1987); *Storey Oil Co., Inc.*, 71 FERC ¶ 63,010, at 65,074 (1995), *errata*, 72 FERC ¶ 63,015 (1995)).

in the instant case. Golden Spread alleges that the Initial Decision's reliance on *FPL Energy*[41] is misplaced because that decision concerned the impact of a "prior *final order*"[42] in "the *same proceeding*."[43] Golden Spread explains that the Initial Decision circumvented the same case requirement by focusing on the similarity of the evidence presented in the instant proceeding and in the Opinion No. 501 proceeding. Golden Spread avers that this is improper because the same issue can be considered in a new rate proceeding, despite alleged factual similarities between the two proceedings. Golden Spread further explains that the Initial Decision's interpretation of the law of the case doctrine is at odds with the Commission's decision in Opinion No. 501 that the demand cost allocation methodology must be decided on a case-by-case basis.[44]

26. Golden Spread also argues that, even if the law of the case doctrine could be used to preclude consideration of the same issue in a different proceeding, it cannot be used in this particular proceeding because the two cases relied on to establish the law of the case – Opinion No. 501 and the Docket No. ER08-749-000 Hearing Order – were both pending rehearing when the Presiding Judge invoked them. Golden Spread contends that orders pending rehearing cannot be used to establish the law of the case.[45] Furthermore, Golden Spread asserts that relying on the non-final Opinion No. 501 is inappropriate for the additional reason that the Commission's determination was based on incorrect references to record evidence. Golden Spread states that a proper consideration of the evidence on rehearing in that proceeding will justify a 3 CP demand cost allocator.

27. As to the second alleged legal error, Golden Spread contends that summary disposition was improper because the Initial Decision erroneously concluded that no genuine issues of fact exist. Golden Spread contends that it was not given the opportunity to present all the facts that could have produced a contrary result. Golden Spread asserts that the Initial Decision relies entirely on the expanded table in SPS's motion for summary disposition, which is improper because neither arguments advanced by counsel, nor tables prepared by counsel can be relied upon as evidence in a

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[41] *Electric Utilities – FPL Energy Marcus Hook, L.P. v. PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,289 (2008) (*FPL Energy*).

[42] Golden Spread Sept. 29, 2008 Brief on Exceptions at 13 (emphasis in original).

[43] *Id.* at 14 (emphasis in original).

[44] *Id.* (citing Opinion No. 501, 123 FERC at 61,249).

[45] Golden Spread Sept. 29, 2008 Brief on Exceptions at 15 (citing *Tarpon Transmission Co.*, 42 FERC ¶ 61,188, at 61,665 (1988)).

proceeding.[46] Accordingly, Golden Spread asserts that the expanded table is not evidence in this proceeding, and the Presiding Judge in the Initial Decision erred by treating it as such. Further, Golden Spread states that SPS's expanded table omits data and studies presented by Mr. Linxwiler. Moreover, even if the chart was properly considered evidence, Golden Spread contends that it should have the right to make an objection, submit rebuttal evidence, and cross-examine the witness that presented the table.[47]

28. Golden Spread contends that the Initial Decision erred in concluding that the evidence presented in the instant proceeding is essentially the same as the evidence presented in Opinion No. 501 and Docket No. ER08-749-000.[48] In addition, Golden Spread asserts that the perceived similarity of evidence in the three proceedings provided insufficient grounds for the Presiding Judge to conclude summarily that SPS was a 12 CP utility. Golden Spread states that, in actuality, the facts of the instant proceeding are significantly different from those in Opinion No. 501 and Docket No. ER08-749-000, and that the summary disposition improperly foreclosed Golden Spread's opportunity to present evidence of these changes on the SPS system.[49]

29. As to the third alleged legal error, Golden Spread argues that the Initial Decision misconstrued the December 2007 Settlement Agreement by indicating that it precluded the introduction of additional evidence at hearing.[50] Golden Spread contends that the Initial Decision erroneously concluded, based on a misreading of the December 2007 Settlement Agreement, that no genuine issues of fact existed that would lessen the relevance of Opinion No. 501. Golden Spread states that such issues of fact do exist and the December 2007 Settlement Agreement merely referenced the fact that the prefiled testimony stage of the proceeding was complete, not that the parties agreed to a paper hearing based solely on that prefiled testimony.[51] Golden Spread argues that the Presiding Judge's interpretation of the December 2007 Settlement Agreement deprived Golden Spread of its right to present necessary evidence and conduct cross-examination.

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[46] *Id.* at 21.

[47] *Id.* at 21-22.

[48] *Id.* at 23.

[49] *Id.* at 26.

[50] *Id.* at 27.

[51] *Id.* at 28.

30. As to the fourth alleged legal error, Golden Spread argues that the Initial Decision acknowledged the importance of establishing the demand cost allocator on a case-by-case basis but then erred by not doing so in this instance.[52] Golden Spread contends that the Initial Decision ignored the Commission precedent from *Illinois Power*,[53] which precludes summary disposition when the underlying facts may differ due to a difference in test periods.[54] Golden Spread asserts that the difference in test periods for Opinion No. 501 and the instant proceeding might, by itself, warrant different demand cost allocators, but that the Initial Decision arbitrarily distinguished the instant proceeding from *Illinois Power* based on the elapsed time between the test periods in each case.[55]

2. **Briefs Opposing Exceptions**

31. SPS, Cap Rock, Trial Staff, and the New Mexico Cooperatives (collectively, Respondents) all filed separate briefs opposing Golden Spread's exceptions to the Initial Decision. As an initial matter, the Respondents assert that Golden Spread has not raised any policy considerations that warrant Commission review of the Initial Decision.[56]

32. The Respondents disagree with Golden Spread regarding the Presiding Judge's application of the law of the case doctrine to this proceeding. SPS argues that the policy behind the law of the case doctrine applies here, because the Commission has a policy against relitigation of issues absent a showing that circumstances have changed significantly.[57] SPS contends that this policy is applicable in the instant proceeding because the Commission decided the demand allocation issue in Opinion No. 501 based on virtually the same facts presented in the instant docket.[58] According to Cap Rock and the New Mexico Cooperatives, the Presiding Judge did not rely solely on the law of the case doctrine, but instead looked at the entire record and granted summary disposition

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[52] *Id.* at 29-30.

[53] *Illinois Power Co.*, 59 FPC 2245, *reh'g denied*, 1 FERC ¶ 61,174.

[54] Golden Spread Sept. 29, 2008 Brief on Exceptions at 30.

[55] *Id.* at 31.

[56] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 4; Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 13-15; Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 11-12; SPS Oct. 20, 2008 Brief Opposing Exceptions at 4-5.

[57] SPS Oct. 20, 2008 Brief Opposing Exceptions at 5-6.

[58] *Id.* at 5.

pursuant to Rule 217 of the Commission's Rules of Practice and Procedure.[59] Trial Staff contends that the Presiding Judge appropriately applied the doctrine because the Commission is a "higher decisional authority" that has already resolved this issue in Opinion No. 501 and Docket No. ER08-749-000.[60] The New Mexico Cooperatives argue that Golden Spread has undermined its own arguments by conceding that the Commission's prior determination on the demand cost allocator should control absent subsequent facts showing a significant change in circumstances. According to the New Mexico Cooperatives, the Initial Decision properly concluded that the evidence does not reveal any such change.[61]

33. The Respondents assert that the Presiding Judge correctly found that no genuine issues of material fact exist and, therefore, appropriately granted summary disposition.[62] The Respondents claim that Golden Spread had sufficient opportunity to present its arguments and factual support. SPS claims that Golden Spread has not been deprived of any procedural rights.[63] Cap Rock posits that Golden Spread's grievance that it was denied the chance to cross-examine witnesses does not, by itself, provide a right to a hearing.[64] Similarly, Trial Staff argues that Rule 505 of the Commission's Rules of Practice and Procedure does not provide an absolute right to cross-examination.[65] The New Mexico Cooperatives assert that Golden Spread was provided ample opportunity to rebut and cross-examine the evidence in SPS's expanded chart, and that Golden Spread's claim concerning its opportunity for cross-examination is irrelevant due to the limitations included in the Order Establishing Hearing Schedule and the Presiding Judge's Rules for Conduct of Hearings.[66] The New Mexico Cooperatives also reject Golden Spread's argument that it was deprived of the opportunity to present post-test year data, stating that

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[59] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 13; New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 4-5.

[60] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 18.

[61] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 8.

[62] *Id.* at 9; Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 25; Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 13; SPS Oct. 20, 2008 Brief Opposing Exceptions at 6.

[63] SPS Oct. 20, 2008 Brief Opposing Exceptions at 10.

[64] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 16-17.

[65] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 28.

[66] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 12-13.

this argument is contrary to Commission precedent and to Golden Spread's own arguments in the Opinion No. 501 proceeding.[67] The New Mexico Cooperatives contend that Golden Spread's view of cross-examination would be contrary to Commission policy and would nullify Rule 217.[68]

34. With regard to the evidentiary record, the Respondents reject Golden Spread's characterization of SPS's expanded table as mere argumentation, rather than evidence.[69] SPS further contends that Golden Spread's characterization of the expanded table is inaccurate and misleading. SPS explains that all relevant pre-filed written testimony was submitted to the Presiding Judge and, because the 2006 test period has passed, there is no new evidence for Golden Spread to present at an evidentiary hearing.[70] SPS further contends that any differences in the data between the Opinion No. 501 test year and the test year in the instant case are non-material.[71] SPS also disagrees with Golden Spread's argument that future changes to the SPS system necessitate a full evidentiary hearing. According to SPS, any such future changes are irrelevant because this case involves a locked-in period.[72]

35. Cap Rock argues that Golden Spread has failed to show that summary disposition was inappropriate or that the Presiding Judge's determination regarding SPS's demand cost allocator was wrong. Cap Rock contends that the Presiding Judge correctly found that no genuine issue of material fact exists because the parties' evidence shows nearly identical peak load test ratios applicable to the SPS system, and those ratios support a 12 CP methodology.[73] Cap Rock asserts that, contrary to Golden Spread's claims, there is no indication that the Presiding Judge failed to view the evidence in the light most favorable to Golden Spread.[74] Cap Rock contends that Golden Spread has failed to show

[67] *Id.* at 13-14.

[68] *Id.* at 14-15.

[69] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 11; Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 26-28; Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 15-16; SPS Oct. 20, 2008 Brief Opposing Exceptions at 8-9.

[70] SPS Oct. 20, 2008 Brief Opposing Exceptions at 9.

[71] *Id.*

[72] *Id.* at 11.

[73] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 14.

[74] *Id.* at 15.

that the expanded table submitted by SPS contained any factual errors or that the Presiding Judge relied on it for anything but a summary of the parties' positions.[75]

36. The New Mexico Cooperatives state that no genuine issue of fact exists regarding the ratios submitted in the witnesses' testimonies nor is there a genuine issue of fact that the ratios fall within the range that Opinion No. 501 determined was indicative of a 12 CP utility. The New Mexico Cooperatives argue that, under Golden Spread's approach, summary disposition would never be appropriate and a hearing, including cross-examination, would always be required regardless of whether genuine issues of fact exist.[76]

37. Trial Staff contends that SPS's expanded table was properly considered as evidence and, even if that were not the case, all of the information in SPS's expanded table is still in the record as evidence in this proceeding.[77] Trial Staff asserts that the Initial Decision correctly concluded that Docket Nos. EL05-19 and ER08-749 are based on essentially the same evidence as the instant proceeding. Trial Staff explains that the new data that Golden Spread claims it was precluded from submitting are irrelevant to the locked-in period in this proceeding, even though these data might be relevant to the proceeding in Docket No. ER08-749.[78]

38. Some of the parties disagree with Golden Spread regarding the impact of the December 2007 Settlement Agreement on the hearing, and the Initial Decision's treatment of that settlement.[79] The New Mexico Cooperatives argue that Golden Spread ignores the fact that the December 2007 Settlement Agreement precluded the submittal of additional evidence on the demand cost allocator issue in this proceeding. According to the New Mexico Cooperatives, the December 2007 Settlement Agreement preserved the settling parties' right to make legal arguments on the issue, but not to submit new facts and evidence into the record.[80] Trial Staff asserts that Golden Spread misconstrues the Initial Decision's interpretation of the December 2007 Settlement Agreement. According to Trial Staff, the Presiding Judge simply described the December 2007 Settlement

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[75] *Id.* at 15-16.

[76] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 14.

[77] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 27.

[78] *Id.* at 30.

[79] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 15-16; Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 31-32.

[80] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 16.

Agreement and its effect on the relevance of Opinion No. 501, but the Presiding Judge did not imply that the agreement had any effect on the parties' cross-examination rights in the instant proceeding.[81]

39. Some parties refute Golden Spread's argument that the Presiding Judge did not conduct a case-by-case analysis to determine SPS's demand cost allocator for the Locked-In Period.[82] Cap Rock asserts that there is no Commission precedent requiring the Presiding Judge to ignore the Commission's orders immediately before and after the Locked-In Period.[83] Cap Rock points out that Golden Spread has argued that such decisions should be a factor in resolving the demand allocation methodology.[84] SPS contends that Golden Spread had the opportunity to present more recent data to inform the case-by-case analysis in this proceeding, but that Golden Spread presented no evidence showing a change in the relevant circumstances between the test period in Opinion No. 501 and the test period in the instant case. SPS concludes that the lack of evidence showing changed circumstances justified the summary disposition.[85]

40. The Respondents disagree with Golden Spread's contention that Opinion No. 501 and the Docket No. ER08-749-000 Hearing Order are not final orders and thus cannot be relied upon as the basis for granting summary disposition.[86] The Respondents assert that the Commission and the Presiding Judge may rely on those orders despite the pending rehearing requests and possibility of appeal. Cap Rock, Trial Staff, and the New Mexico Cooperatives point out that, in Docket No. ER08-749, the Commission has already rejected Golden Spread's argument regarding the precedential effect of Opinion No. 501 and Docket No. ER08-749.[87] SPS asserts that the Commission has explained that it may

[81] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 31.

[82] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 17; SPS Oct. 20, 2008 Brief Opposing Exceptions at 12-13.

[83] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 17.

[84] *Id.*

[85] *Id.* at 13.

[86] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 16-17; Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 33; Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 19-20; SPS Oct. 20, 2008 Brief Opposing Exceptions at 13.

[87] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 33; Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 20; New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 16-17.

rely on contested orders as final Commission orders, despite pending rehearing requests or appeals, unless they have been stayed.[88] Cap Rock contends that a Commission order becomes final when it "imposes an obligation, denies a right, or fixes some legal relationship as a consummation of the administrative process[,]"[89] and that both Opinion No. 501 and the Docket No. ER08-749-000 Hearing Order qualify as final orders. Furthermore, Cap Rock contends that Golden Spread's argument, if successful, would allow utilities to ignore a Commission order until it is no longer subject to judicial review.[90]

41. Cap Rock disagrees with Golden Spread's claim that the Initial Decision allowed SPS to avoid its obligation under FPA section 205 to show that the 12 CP demand allocation methodology is just and reasonable.[91] Cap Rock states that SPS met this burden through its motion for summary disposition and witness testimony. Trial Staff argues that the Commission's review of the Initial Decision must simply address whether the record would lead a reasonable trier of facts to find no material issues of disputed fact.[92] Trial Staff contends that the Presiding Judge's ruling was not arbitrary and was supported by Commission precedent. Trial Staff also argues that a difference in test periods between two proceedings could warrant different demand allocator determinations, but such a result is not automatic, and the Presiding Judge reasonably found that different determinations were not warranted in this instance.[93]

C. Commission Determination

42. Because the Commission is reversing the demand cost allocator determination in Opinion No. 501 in an order being issued concurrently,[94] we will not rule on the Presiding Judge's grant of summary disposition. However, in light of the outcome in Opinion No. 501-A, we will make a determination on the appropriate demand cost allocation methodology for the SPS system based on the record in this proceeding. In

[88] SPS Oct. 20, 2008 Brief Opposing Exceptions at 13-14.

[89] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 19.

[90] *Id.* at 20.

[91] *Id.* at 18.

[92] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 17.

[93] *Id.* at 32-33.

[94] Opinion No. 501-A, 144 FERC ¶ 61,132.

doing so, we find that a 3 CP demand cost allocation methodology is appropriate for the SPS system during the Locked-In Period.

43. The Commission has stated that in selecting the proper demand cost allocation methodology, the full range of a utility's operating realities should be considered, including system demand and off-system sales commitments.[95] In the instant proceeding, the parties submitted their initial, rebuttal, and answering testimony on the demand allocation issue, and no party sought reconsideration of the Presiding Judge's Scheduling Order requiring the parties to re-submit that same testimony more than two years after the 2005-2006 test year. Therefore, we conclude that the record contains sufficient information for us to resolve the demand cost allocation issue.

44. We agree with Golden Spread that SPS's sales to EPE and PNM were off-system opportunity sales that should be excluded from the load ratio calculations for the SPS system. The sales at issue in the instant case are very similar to those the Commission found to be off-system opportunity sales in Opinion No. 501.[96] As with the off-system sales in Opinion No. 501, the record in this proceeding does not indicate that SPS planned for and constructed its system, or made purchases, to facilitate the sales to EPE and PNM. SPS's sales to EPE and PNM were market-based opportunity sales to customers outside SPS's control area that have a lower curtailment priority than SPS's native load customers.[97] Further, the PNM sale at issue was transacted at a time when SPS had surplus capacity.[98] Including these off-system opportunity sales in the peak load tests would impermissibly skew the test results. Therefore, we find that SPS's sales to EPE and PNM should be excluded from SPS's load calculations when determining the appropriate demand cost allocator for the Locked-In Period. As explained below, analyzing SPS's system demand, after excluding the off-system sales to EPE and PNM, indicates that SPS remains a 3 CP utility.

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[95] *Carolina Power*, 4 FERC ¶ 61,107, at 61,230 (1978); *Illinois Power Co.*, 11 FERC ¶ 63,040, at 65,248-49 (1980) (*Illinois Power Initial Decision*), *aff'd*, 15 FERC ¶ 61,050 (1981). *See also* Opinion No. 501-A, 144 FERC ¶ 61,132 at P 52 (explaining that excluding off-system opportunity sales for which SPS does not plan its system is consistent with the principle of cost-causation, which requires that the parties who cause the costs should bear the costs (citing *Cincinnati Gas & Electric Co.,* 71 FERC ¶ 61,380, at 62,478 n.30 (1995)).

[96] Ex. GSE-1 at 26.

[97] Ex. SPS-47 at 9-12.

[98] Ex. GSE-1 at 25.

45. The Commission has stated that substantive ratemaking principles, such as demand allocation, once established for a particular company, should continue to be applied in subsequent cases unless there is a supervening change in circumstances or Commission policy requiring a different conclusion.[99] In each of SPS's last three rate cases—Opinion No. 162, in 1983;[100] Opinion No. 337, in 1989;[101] and Opinion No. 501-A, issued concurrently with this order[102]—the Commission determined that SPS was a summer peaking utility for which a 3 CP demand cost allocation methodology was appropriate. Conducting a comparable analysis in the instant proceeding indicates there has been no supervening change in circumstances or Commission policy that warrants a change in SPS's demand cost allocator for the Locked-In Period.

46. The Commission has historically focused on three separate peak load tests when analyzing the demand cost allocation methodology appropriate for a given utility. The first test is the On and Off Peak Test, whereby the Commission compares the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak.[103] The second test is the Low to Annual Peak Test, in which the Commission calculates the lowest monthly peak as a percentage of the annual peak.[104] The third test is

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[99] *Louisiana Power & Light Company*, Opinion No. 110, 14 FERC ¶ 61,075, at 61,128 (1981).

[100] Opinion No. 162, 22 FERC ¶ 61,341 (1983).

[101] *Southwestern Pub. Serv. Co.*, Opinion No. 337, 49 FERC ¶ 61,296 (1989).

[102] Opinion No. 501-A, 144 FERC ¶ 61,132.

[103] Under this test, the Commission has held that, in general, a 19 percentage point or less difference between these two figures indicates using the 12 CP demand allocation methodology is appropriate. *See Illinois Power Initial Decision*, 11 FERC at 65,248-49 (comparing average summer peak of 94 percent of annual peak to eight-month average peak of 75 percent of annual peak, a difference of 19 percentage points).

[104] Under this test, the Commission has held that a range of 66 percent or higher is indicative of a 12 CP system. *See id.* (approving 12 CP where lowest monthly peak as percentage of annual peak was 66 percent); *Delmarva Power & Light Co.*, 17 FERC ¶ 63,044, at 65,201 (1981) (*Delmarva Initial Decision*), *aff'd*, Opinion No. 185, 24 FERC ¶ 61,199 (1983), *reh'g denied*, Opinion No. 185-A, 24 FERC ¶ 61,380 (1983) (stating that for the Low to Annual Peak test, a low percentage indicates a load curve with a clearly defined peak, while a high percentage indicates a flatter load curve).

the Average to Annual Peak Test, whereby the Commission computes the average of the 12 monthly peaks as a percentage of the annual peak.[105] Commission precedent has set certain benchmarks against which the results of these tests are compared to help determine the appropriate demand allocation for a particular utility.[106]

47. When comparing the results of the three peak load tests in this proceeding (calculated without SPS's sales to EPE and PNM) to the benchmarks established by the Commission in prior cases, one test – the On and Off Peak Test – indicates that SPS is a 3 CP utility; one test – the Low to Annual Peak Test – indicates that SPS is a 12 CP utility; and one test – the Average to Annual Peak Test – barely leans toward a 12 CP demand allocator. The table below reflects the results of these peak load tests calculated using SPS's load data for 2001 through 2006, excluding the off-system sales.[107]

	Low to Annual Peak	On and Off Peak	Average to Annual Peak
Historical Commission Minimum for 12 CP	66% or higher	19% or less	81% or higher
2001	69.07	22.14	80.22
2002	67.14	21.36	81.2
2003	65.56	19.43	79.59

[105] Under this test, the Commission has held that the range indicating whether a utility is to be considered a 12 CP system is 81 percent or higher. *See Illinois Power Initial Decision*, 11 FERC at 65,249 (approving 12 CP where average monthly peak for five-year period was 81 percent); *Lockhart Power Co.*, Opinion No. 29, 4 FERC ¶ 61,337, at 61,807 (1978) (approving 12 CP where average monthly demand was 84 percent of annual system peak); *El Paso Elec. Co.*, Opinion No. 109, 14 FERC ¶ 61,082, at 61,147 (1981) (approving 12 CP where twelve-month average was 84 percent of maximum peak).

[106] *See supra* n.103, n.104, n.105.

[107] The Commission excluded from the chart load data from 2000 because that was an anomalous year on the SPS system. During that year, Golden Spread converted from full requirements to partial requirements service. Thus, a portion of the load data for 2000 reflects Golden Spread's full requirements service and is not representative of the demands placed on SPS's system during the locked-in period.

2004	67.13	22.89	80.47
2005	70.75	19.54	83.61
2006	68.99	20.98	82.31
Average 2001 - 2006	68.11	21.22	81.23

48. When the above results are compared to the results of the same peak load tests in Opinion Nos. 162 and 501-A, the numbers are not especially different—ranging less than two percentage points in each test. In all three cases, the test results are split, with at least one test indicating that a 3 CP demand cost allocator is appropriate and at least one test indicating that a 12 CP demand cost allocator is appropriate.

	Low to Annual Peak	On and Off Peak	Average to Annual Peak
Historical Commission Minimum for 12 CP	66% or higher	19% or less	81% or higher
Opinion No. 162	66.98	22.9	80.1
Opinion No. 501-A	66.2	21.7	79.9
Average 2001 -2006	68.11	21.22	81.23

49. The load ratios in the above tables indicate that SPS's system demand during the Locked-In Period is not significantly different from the system demand in SPS's past rate cases. In each of the rate cases, the results of the peak load tests are split, and all of them are close to the thresholds the Commission has historically used in applying these tests.

50. Because the results of the three primary peak load tests are not the only indicators of a change on SPS's system, we will also consider the two additional tests that the Commission conducted in Opinion No. 501-A. The first test measures the number of times the non-summer monthly peak demand exceeds the summer monthly peak

demand.[108] For SPS, the non-summer monthly peak demand was greater than the lowest summer peak month only one time during the period from 2001 to 2006.[109] The second test computes the number of times the non-summer monthly peak demand exceeds the summer monthly peak demand in the preceding year.[110] For SPS, the non-summer peak demand only twice exceeded the summer peak demand of a prior year over the period from 2001 to 2006.[111] Thus, the results of these two additional peak load tests tend to support the use of a 3 CP demand allocator for SPS. Notably, the results of these two tests point even more strongly towards a 3 CP demand allocator for the Locked-In Period than the same tests did in Opinion No. 501-A. The following table compares the results of these additional load tests in each proceeding.

	# of non-peak months greater than peak months	non-peak months exceeding prior year peak months
Opinion No. 501-A (Average of 2001 - 2004)	0.5 per year (3 CP)	1 per year (3 CP)
Docket No. ER06-274-000 (Average of 2001 - 2006)	0.17 per year (3 CP)	0.6 per year (3 CP)

51. As we explained above, the standard for changing a substantive ratemaking principle, such as the proper demand allocator, is that there must be a supervening change in circumstances or Commission policy to warrant a change. Here, we do not find a change in SPS's system demand significant enough to warrant changing to a 12 CP demand cost allocator. While the results of the peak load tests here have moved slightly toward a 12 CP demand allocator, one test still clearly supports a 3 CP demand allocator and the results of all three load tests are close to the results from Opinion Nos. 162 and 501-A, in each of which the Commission determined SPS was a 3 CP utility. In addition,

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[108] Opinion No. 501-A, 144 FERC ¶ 61,132 at P 57; *Carolina Power & Light*, 4 FERC ¶ 61,107 (1978), *reh'g granted on other grounds*, 5 FERC ¶ 61,081 (1978)).

[109] *See* Ex. GSE-51.

[110] Opinion No. 501-A, 144 FERC ¶ 61,132 at P 57; *Consumers Energy Co.*, 86 FERC ¶ 63,004 (1999), *aff'd*, 98 FERC ¶ 61,333 (2002)).

[111] *See* Ex. GSE-51.

the two additional peak load tests we conducted both indicate, even more strongly than they did in Opinion No. 501-A, that SPS is a 3 CP utility.

52. We conclude that the corrected load data and the peak load tests, taken together, indicate that SPS is a 3 CP utility. However, system demand is only one of the operating realities the Commission must consider. We will also look at the other evidence the parties submitted concerning SPS's system, specifically SPS's scheduled maintenance and operating reserves during the test year.[112]

53. With regard to scheduled maintenance, the record demonstrates that during the 2005-2006 test year, SPS conducted no scheduled maintenance during June, July, and August; and between 2001-2006, SPS only once conducted scheduled maintenance in those three months.[113] While not conclusive, this is certainly more indicative of a 3 CP utility than a 12 CP utility. If summer were not a critical time for peak load, SPS would spread its system maintenance activities more evenly throughout the year. Similarly, with regard to operating reserves, the record shows that SPS's operating reserves, as a percentage of peak load, were consistently lower in the peak summer months than in the non-summer months.[114] During the 2001-2006 period, there were very few non-summer months in which the operating reserves dropped below the reserve level of a peak summer month.[115] The existence of lower operating reserves in the peak summer months indicates that SPS is generally more concerned with meeting its reserve margins in summer months than in non-summer months. Thus, as with the data concerning SPS's

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[112] The Commission has, in the past, considered other operating realities; specifically, a utility's unscheduled outages and diversity. *E.g.*, Opinion No. 501-A, 144 FERC ¶ 61,132 at PP 60-61. We do not address unscheduled outages and diversity in the instant order because the record contains limited data on these considerations.

[113] Ex. GSE-51 at 1-6. The one instance of scheduled maintenance occurring in June, July, or August was in July of 2002.

[114] *Id.*

[115] In 2003, the reserve margins in May and September were lower than the reserve margin in June. *Id.* at 3. In 2005, the reserve margin in September was lower than the reserve margin in all three of the peak summer months. *Id.* at 5; *see also* Ex. SPS-64 at 2. In addition, the record contains conflicting data entries for 2006—the entry in Exhibit GSE-51 shows that the three peak summer months have the lowest reserve margins for that year, while the entry in Exhibit SPS-64 shows that the reserve margin in May was lower than the reserve margins in June and August. *Compare* Ex. GSE-51 at 6 *with* Exhibit SPS-64 at 3.

scheduled maintenance, the data on SPS's operating reserves are more indicative of a 3 CP utility than a 12 CP utility.

54. These operational realities, combined with the load ratio tests, demonstrate that SPS's load profile has not changed sufficiently to justify a change to a 12 CP demand cost allocator. Accordingly, we find that a 3 CP demand cost allocation methodology is appropriate for SPS during the Locked-In Period.

The Commission orders:

(A) The Initial Decision is hereby reversed, as discussed in the body of this order.

(B) SPS is hereby directed to file, within 30 days of the date of this order, a compliance filing quantifying refunds relating to cost of service rates from July 1, 2006 through June 30, 2008.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

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Via e-mail scampbell@stewartmckelvey.com

Stewart McKelvey
Barristers & Solicitors
65 Grafton Street
PO Box 2140
Charlottetown, PE C1A 8B9

Attention: D. Spencer Campbell, Q.C.

Dear Mr. Campbell:

Re: Maritime Electric Company, Limited's ("MECL")/Summerside Electric/OATT 2017

Thank you for your note of December 15, 2016 in response to the inquiries posed by Summerside Electric and arising from our discussion at Credit Union Place with yourself, John Gaudet and Bob Younker.

As indicated previously, we believe that this discussion was both informative and helpful insofar as our mutually expressed desire to ensure that the final OATT as approved is best suited for all rate payers in the Province.

In the same way, we appreciate the responses to the inquiries which we had forwarded to you on December 7, 2016.

With respect to your responses, there are just a few remaining clarifications required. As discussed, it is our hope that we can avoid extensive hearings at IRAC through a full and open exchange in advance. To that end, we would ask that you have MECL consider and respond to the following:

With respect to question 2:

a) Further to the Excel workbook that you have provided, it would be helpful if you could provide a similar breakdown with respect to MECL's native load as well as the same for the PEI Peak load. The results provided are not consistent with our expectations and therefore this additional information may be helpful to better understand this discrepancy.

b) I would ask that you provide the FERC calculation using the metric of MECLs load including firm point to point transmission reservations.

c) There appear to be options available with respect to how the FERC calculations are performed and what metrics are used. Please confirm MECLs opinion and rationale for the method of testing used by them.

d) Subject to the results arising from the additional inquires noted above, is MECL prepared to consider a three CP method that might better reflect FERC standards?

With respect to question 3:

a) Please confirm if MECL currently incurs a cost for these scheduling inaccuracies due to wind? If MECL does incur such a cost, please provide the data that supports these costs.

With respect to question 7:

a) I would ask that you provide a copy of the system impact study that was completed prior to commencement of construction for the Y-104 line. Additionally, if there are additional or supplementary system impact studies for this line, please provide them as well.

With respect to question 8:

a) We would note that the two maps that you provided in connection with question 8 are not one-line diagrams. These appear to be geographical maps. Please provide the one-line diagrams that show the detail connections at the various substations.

With respect to the proposed industrial bypass:

a) I would ask that you comment on the rationale used by MECL to include a bypass for only one class of customer as proposed within the current iteration of the OATT.

Spencer, I believe that upon receipt of this information we will be in a better position to determine how best to move forward in our efforts to ensure a full, complete and appropriate OATT when finally approved by IRAC.

Thank you for your consideration in these regards, I remain,

Yours very truly,

Derek D. Key, Q.C.

DDK/akm

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Ryan MacDonald

From:	Spencer Campbell <scampbell@stewartmckelvey.com>
Sent:	Wednesday, January 25, 2017 11:46 AM
To:	Derek Key
Cc:	Ryan MacDonald
Subject:	Responses for City re OATT 15042-103dk
Attachments:	20170104152952614.pdf; Coincident peak loads.xlsx; CP FERC tests.xlsx; CP tests FERC 20130815123655-ER06-274-007.pdf; 2005 transmission expansion plan.pdf; Jan 4 2017 questions from Sside.docx; System SLD with and without Y104.docx

Derek:

Please see attached responses.

The attachments are:

Adobe	20170104152952614	Questions from Derek Key
Word	Jan 4 2017 questions from Sside	Written responses
Excel	Coincident peak loads	Question 2(a)
Excel	CP FERC tests	Question 2(b).
Adobe	CP tests FERC 20130815123655-ER06-274-007	Question 2 ('c)
Adobe	2005 transmission expansion plan	Question 7
Word	System SLD with and without Y104	Question 8

Spencer

A

2013 PEI MONTHLY COINCIDENT PEAK LOADS

2013 PEI MONTHLY COINCIDENT PEAK LOADS

2013	Date	Hour ending	PEI peak load (MW)	Maritime Electric portion (MW)	Summerside portion: Purchases (MW)	Summerside portion: Generation (MW)	Summerside portion: Total (MW)	Summerside transmission usage: Firm Pt-to-Pt (MW)	Summerside transmission usage: Non-firm Pt-to-Pt (MW)	Summerside transmission usage: Total (MW)
Jan	23	19:00	242.5	217.4	16.0	9.1	25.1	10.0	6.0	16.0
Feb	7	19:00	240.0	215.6	18.6	5.8	24.4	10.0	8.6	18.6
Mar	18	10:00	200.5	179.3	10.0	11.2	21.2	10.0	-	10.0
Apr	1	17:00	185.5	165.7	8.1	11.7	19.8	10.0	-	8.1
May	18	12:00	173.6	157.0	4.8	11.8	16.6	10.0	-	4.8
Jun	25	12:00	183.4	164.7	18.0	0.7	18.7	10.0	8.0	18.0
Jul	15	18:00	195.6	176.5	18.6	0.5	19.1	10.0	8.6	18.6
Aug	21	18:00	186.0	168.6	11.8	5.6	17.4	10.0	1.8	11.8
Sep	3	13:00	178.9	161.3	8.4	9.2	17.6	10.0	-	8.4
Oct	30	20:00	188.9	170.6	14.8	3.5	18.3	10.0	4.8	14.8
Nov	25	18:00	227.1	204.4	16.8	5.9	22.7	10.0	6.8	16.8
Dec	12	18:00	251.8	226.6	21.4	3.8	25.2	10.0	11.4	21.4
			Average	184.0						

2014 PEI MONTHLY COINCIDENT PEAK LOADS

2014 PEI MONTHLY COINCIDENT PEAK LOADS

					Summerside portion			Summerside transmission usage		
2014	Date	Hour ending	PEI peak load (MW)	Maritime Electric portion (MW)	Purchases (MW)	Generation (MW)	Total (MW)	Firm Pt-to-Pt (MW)	Non-firm Pt-to-Pt (MW)	Total (MW)
Jan	3	18:00	243.8	219.3	13.3	11.2	24.5	10.0	3.3	13.3
Feb	6	20:00	236.9	214.1	18.8	4.0	22.8	10.0	8.8	18.8
Mar	5	20:00	225.4	202.6	20.8	2.0	22.8	10.0	10.8	20.8
Apr	24	17:00	196.4	175.8	10.4	10.2	20.6	10.0	0.4	10.4
May	5	18:00	189.4	172.1	6.8	10.5	17.3	10.0	-	6.8
Jun	30	17:00	181.0	162.9	16.2	1.9	18.1	10.0	6.2	16.2
Jul	4	12:00	194.1	174.7	10.4	9.0	19.4	10.0	0.4	10.4
Aug	5	18:00	195.0	177.3	17.5	0.2	17.7	10.0	7.5	17.5
Sep	3	12:00	184.9	166.7	11.1	7.1	18.2	10.0	1.1	11.1
Oct	27	19:00	195.6	177.5	11.6	6.5	18.1	10.0	1.6	11.6
Nov	27	18:00	225.0	202.6	14.8	7.6	22.4	10.0	4.8	14.8
Dec	30	18:00	254.5	227.7	22.9	3.9	26.8	10.0	12.9	22.9
			Average	189.4						

Coincident peak loads
17-01-06

2015 PEI MONTHLY COINCIDENT PEAK LOAD!

2015 PEI MONTHLY COINCIDENT PEAK LOAD!

2015	Date	Hour ending	PEI peak load (MW)	Maritime Electric portion (MW)	Summerside portion Purchases (MW)	Summerside portion Generation (MW)	Summerside portion Total (MW)
Jan	6	18:00	263.9	236.0	25.5	2.4	27.9
Feb	2	18:00	254.1	229.7	23.7	0.7	24.4
Mar	6	20:00	232.5	208.3	20.8	3.4	24.2
Apr	10	11:00	198.4	176.6	16.0	5.8	21.8
May	12	12:00	183.5	165.0	8.5	10.0	18.5
Jun	3	18:00	182.7	165.2	8.1	9.4	17.5
Jul	31	12:00	189.6	171.4	16.4	1.8	18.2
Aug	19	17:00	204.9	184.3	19.7	0.9	20.6
Sep	7	21:00	182.6	166.0	7.2	9.4	16.6
Oct	19	20:00	193.0	173.5	19.5	-	19.5
Nov	30	18:00	235.2	211.1	21.1	3.0	24.1
Dec	28	18:00	240.6	215.6	17.4	7.6	25.0
			Average	191.9			

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Summerside transmission usage		
Firm Pt-to-Pt (MW)	Non-firm Pt-to-Pt (MW)	Total (MW)
10.0	15.5	25.5
10.0	13.7	23.7
10.0	10.8	20.8
10.0	6.0	16.0
10.0	-	8.5
10.0	-	8.1
10.0	6.4	16.4
10.0	9.7	19.7
12.0	-	7.2
12.0	7.5	19.5
12.0	9.1	21.1
12.0	5.4	17.4

B

CP FERC tests
17-01-09

FERC TESTS FOR APPROPRIATENESS OF 12CP
DEMAND COST ALLOCATION METHODOLOGY

		MECL monthly coincident net peak loads		
		2013 (MW)	2014 (MW)	2015 (MW)
Jan		217.4	219.3	236.0
Feb		215.6	214.1	229.7
Mar		179.3	202.6	208.3
Apr		165.7	175.8	176.6
May		157.0	172.1	165.0
Jun		164.7	162.9	165.2
Jul		176.5	174.7	171.4
Aug		168.6	177.3	184.3
Sep		161.3	166.7	166.0
Oct		170.6	177.5	173.5
Nov		204.4	202.6	211.1
Dec		226.6	227.7	215.6
1CP	(highest monthly peak; i.e. annual peak)	226.6	227.7	236.0
12CP	(average of the 12 monthly peaks)	184.0	189.4	191.9
Low	(lowest monthly peak)	157.0	162.9	165.0
On-peak	Ratio of average of Dec, Jan & Feb to 1CP	0.970	0.968	0.962
Off-peak	Ratio of average of Mar to Nov to 1CP	0.759	0.787	0.763

FERC tests for appropriateness of 12CP demand cost allocation methodology					Criteria for 12CP
1	Difference between On-peak and Off-peak	0.21	0.18	0.20	0.19 or less
2	Ratio of Low to 1CP	0.693	0.715	0.699	0.66 or higher
3	Ratio of 12CP to 1CP	0.812	0.832	0.813	0.81 or higher

CP FERC tests
16-12-02

DEMAND DETERMINANTS FOR 2014 BASED ON 3CP
(Winter peaking months of Jan, Feb and Dec)

Services			2014 usage (MW)	2014 usage (MWh)	Transmission Service equivalent firm (MW)		Schedules 1 and 2 equivalent firm (MW)	
Long term firm Point-to-Point reservations			-		-		-	
Average of 3 CP for MECL load (Network)			219.9		219.9		219.9	
Average of 3 CP for Sside load (Network)			-		-		-	
Short term firm Point-to-Point service:								
- Summerside	(average for 3 months)		10.0		10.0		10.0	
Non-firm Point-to-Point service:								
- Summerside	on-peak	(Jan, Feb and Dec)		8,613	8.3	(Appalachian)	8.3	(Appalachian)
	off-peak	(Jan, Feb and Dec)		2,921	1.4		1.4	
- West Cape wind	on-peak	(Jan, Feb and Dec)		49,380	22.9	(non-Appalachian)	47.5	(Appalachian)
	off-peak	(Jan, Feb and Dec)		40,946	19.0		19.0	
					281.4		306.0	

Note: Summerside stopped purchasing from West Cape in October 2014. Therefore all West Cape generation has been shown as exported for sale off-Island for 2014. Also, Summerside's on-peak non-firm Point-to-Point service quantity has been increased by the amount purchased from West Cape during on-peak in 2014.

CP FERC tests
16-12-02

DEMAND DETERMINANTS FOR 2014 BASED ON 3CP

Services		2014 usage (MW)	2014 usage (MWh)	Transmission Service equivalent firm (MW)		Schedules 1 and 2 equivalent firm (MW)	
Long term firm Point-to-Point reservations		-		-		-	
Average of 12 CP for MECL load (Network)		189.0		189.0		189.0	
Average of 12 CP for Sside load (Network)		-		-		-	
Short term firm Point-to-Point service:							
- Summerside	(average for 12 months)	10.0		10.0		10.0	
Non-firm Point-to-Point service:							
- Summerside	on-peak		24,621	5.9	(Appalachian)	5.9	(Appalachian)
	off-peak		6,856	0.8		0.8	
- West Cape wind	on-peak		155,799	17.8	(non-Appalachian)	37.5	(Appalachian)
	off-peak		138,859	15.9		15.9	
				239.3		259.0	

Note: Summerside stopped purchasing from West Cape in October 2014. Therefore all West Cape generation has been shown as exported for sale off-Island for 2014. Also, Summerside's on-peak non-firm Point-to-Point service quantity has been increased by the amount purchased from West Cape during on-peak in 2014.

CP FERC tests
16-12-02

NETWORK AND POINT-TO-POINT TRANSMISSION USAGE
(firm service or equivalent)

	2014 12CP (MW)	Allocation (%)	2014 3CP (Jan, Feb and Dec) (MW)	Allocation (%)
Long term firm Point-to-Point	-		-	
MECL Network	189.0	78.9	219.9	78.2
Summerside Network	-		-	
Summerside short term firm	10.0	4.2	10.0	3.6
Summerside non-firm	6.7	2.8	9.6	3.4
Merchant wind non-firm	33.7	14.1	41.8	14.9
Total	239.4	100.0	281.3	100.0

CP FERC tests
16-12-02

FERC TESTS FOR APPROPRIATENESS OF 12CP
DEMAND COST ALLOCATION METHODOLOGY

		PEI monthly net peak loads		
		2013 (MW)	2014 (MW)	2015 (MW)
Jan		242.5	243.8	263.9
Feb		240.0	236.9	254.1
Mar		200.5	225.4	232.5
Apr		185.5	196.4	198.4
May		173.6	189.4	183.5
Jun		183.4	181.0	182.7
Jul		195.6	194.1	189.6
Aug		186.0	195.0	204.9
Sep		178.9	184.9	182.6
Oct		188.9	195.6	193.0
Nov		227.1	225.0	235.2
Dec		251.8	254.5	240.6
1CP	(highest monthly peak; i.e. annual peak)	251.8	254.5	263.9
12CP	(average of the 12 monthly peaks)	204.5	210.2	213.4
Low	(lowest monthly peak)	173.6	181.0	182.6
On-peak	Ratio of average of Dec, Jan & Feb to 1CP	0.972	0.963	0.958
Off-peak	Ratio of average of Mar to Nov to 1CP	0.759	0.780	0.759

FERC tests for appropriateness of 12CP demand cost allocation methodology					Criteria for 12CP
1	Difference between On-peak and Off-peak	0.21	0.18	0.20	0.19 or less
2	Ratio of Low to 1CP	0.689	0.711	0.692	0.66 or higher
3	Ratio of 12CP to 1CP	0.812	0.826	0.809	0.81 or higher

C

144 FERC ¶ 61,133
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony Clark.

Southwestern Public Service Company | Docket No. ER06-274-007

ORDER ON INITIAL DECISION

(Issued August 15, 2013)

1. On December 1, 2005, Southwestern Public Service Company (SPS) filed, pursuant to section 205 of the Federal Power Act (FPA),[1] revisions to the rates and rate design applicable to SPS's full and partial requirements customers. On August 29, 2008, the presiding Administrative Law Judge (Presiding Judge) issued an Initial Decision granting SPS's motion for summary disposition on the sole remaining issue in the proceeding: the appropriate demand cost allocation methodology for the SPS system during the period from July 1, 2006 to June 30, 2008 (Locked-In Period).[2] Golden Spread Electric Cooperative, Inc. (Golden Spread) filed a brief on exceptions, and SPS, Cap Rock Energy Corporation (Cap Rock), Commission Trial Staff (Trial Staff), and the New Mexico Cooperatives[3] opposed Golden Spread's exceptions. In this order, we reverse the Initial Decision and determine the appropriate demand cost allocation methodology for the Locked-In Period.[4]

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[1] 16 U.S.C. § 824d (2006).

[2] *Southwestern Pub. Serv. Co.*, 124 FERC ¶ 63,015 (2008) (Initial Decision).

[3] For the purposes of this order, the New Mexico Cooperatives are Farmers Electric Cooperative, Inc.; Lea County Electric Cooperative, Inc.; Central Valley Electric Cooperative, Inc.; and Roosevelt County Electric Cooperative, Inc.

[4] Our determination on SPS's demand cost allocator in this order will apply beyond the Locked-In Period for Golden Spread. Unlike other parties in this proceeding, Golden Spread's rates are not at issue in SPS's subsequent rate case, Docket No. ER08-749-000. Therefore, the demand allocator established for SPS in the instant proceeding will apply to SPS's partial requirements customers, including Golden Spread, until SPS
(continued…)

I. Background

2. Demand cost allocation, or demand allocation, refers to the method by which a utility apportions fixed capacity costs among customer classes. The Commission typically allocates demand costs using a coincident peak method, through which demand costs are allocated based on each customer class's load at the time of (or coincident with) the system peak load. The coincident peak may be based, for example, on a single peak month (1 CP), the average of three peak months (3 CP), or the average of peaks in 12 months (12 CP). Typically, a company that has a relatively flat load profile throughout the year would allocate demand costs on a 12 CP basis, which assumes that a utility's load is relatively constant throughout all 12 months of the year. A summer (or winter) peaking company would allocate demand costs more typically on a 3 CP basis, which assumes the load profile peaks during three peak usage months.

3. The Initial Decision's analysis of the appropriate demand cost allocator for the SPS system depends not just on the instant rate case, but also on SPS's rate cases immediately preceding and following the instant rate case. The background on each of these three closely related SPS proceedings is presented in the following order: Docket No. ER06-274-000 (the instant rate case), the Opinion No. 501 proceeding (the SPS rate case preceding this one),[5] and Docket No. ER08-749-000 (the SPS rate case subsequent to this one).[6]

A. ER06-274-000 Proceeding

4. On December 1, 2005, SPS filed revisions to its wholesale full and partial requirements customers' rates and rate design.[7] On January 31, 2006, the Commission conditionally accepted SPS's proposed revisions for filing, suspended the rates to become effective on July 1, 2006, subject to refund, and set the matter for hearing in Docket

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seeks to change the demand cost allocator for its partial requirements customers. Nonetheless, for the sake of simplicity, we will refer to the refund period in the instant proceeding as the Locked-In Period.

[5] *See generally Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co.*, Opinion No. 501, 123 FERC ¶ 61,047, at 61,249 (2008).

[6] *See generally Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,225 (2008) (Docket No. ER08-749-000 Hearing Order).

[7] SPS Dec. 1, 2005 Rate Filing.

No. ER06-274-000.[8] The Commission held the hearing in abeyance pending the outcome of settlement judge procedures.[9]

5. Settlement negotiations were conducted throughout the first half of 2006 and ultimately yielded two settlement agreements: (1) a partial settlement among SPS and its full requirements customers, i.e., the New Mexico Cooperatives and Cap Rock, (Full Requirements Settlement Agreement),[10] and (2) a partial settlement between SPS and the Public Service Company of New Mexico (PNM) (PNM Settlement Agreement).[11] The Full Requirements Settlement Agreement was approved by the Commission on September 20, 2007.[12] The PNM Settlement Agreement was approved by the Commission on September 8, 2008.[13]

6. The Full Requirements Settlement Agreement resolved all issues in Docket No. ER06-274 among SPS, the New Mexico Cooperatives, and Cap Rock, but it reserved those parties' rights to continue litigating the demand allocation issue.[14] The PNM Settlement Agreement resolved, going forward, all issues in Docket No. ER06-274-007 regarding rates charged by SPS to PNM pursuant to their interruptible power service agreement.[15] Under the PNM Settlement Agreement, the rates SPS charged PNM from

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[8] *Southwestern Pub. Serv. Co.*, 114 FERC ¶ 61,091 (2006) (Hearing Order).

[9] *Id.* P 20.

[10] SPS Sept. 7, 2006 Offer of Settlement, *approved in Southwestern Pub. Serv. Co.*, 120 FERC ¶ 61,243 (2007).

[11] SPS Sept. 19, 2006 Offer of Settlement, *approved in Southwestern Pub. Serv. Co.*, 124 FERC ¶ 61,232 (2008).

[12] *Southwestern Pub. Serv. Co.*, 120 FERC ¶ 61,243 (2007).

[13] *Southwestern Pub. Serv. Co.*, 124 FERC ¶ 61,232 (2008).

[14] *Southwestern Pub. Serv. Co.*, 120 FERC ¶ 61,243 at P 18.

[15] *Id.* P 33. The PNM Settlement Agreement also resolved all issues in Docket No. EL05-151-000 except the issues pertaining to SPS's fuel cost adjustment clause. *Id.*

July 1, 2006 until the wholesale partial requirements rates are determined in Docket No. ER06-274-007 are subject to refund.[16]

7. SPS was initially unable to reach a negotiated settlement with one of its partial requirements customers, Golden Spread, and one of its retail customers, Occidental Permian, Ltd. (Occidental). Accordingly, on August 2, 2006, Golden Spread and Occidental were severed from the settlement proceeding in Docket No. ER06-274-000, and hearing procedures were initiated in Docket No. ER06-274-003. The parties submitted testimony in the proceeding; however, the hearing procedures were again suspended on March 29, 2007 to allow the participants to resume settlement negotiations. On December 3, 2007, that round of settlement negotiations resulted in a settlement (December 2007 Settlement Agreement) among SPS, Golden Spread, and Occidental that resolved all issues among those three parties except for the appropriate demand cost allocator methodology for the SPS system.[17] Accordingly, on February 5, 2008, hearing procedures were reinitiated in Docket No. ER06-274-007 to determine the appropriate demand cost allocator for the Locked-In Period.

8. On February 19, 2008, the Presiding Judge issued an Order Establishing Procedural Schedule (Scheduling Order).[18] The Presiding Judge noted the parties' statement, in the December 2007 Settlement Agreement, that the case could be promptly litigated due to the posture of the case with respect to the demand cost allocation issue. The settlement offer stipulated that discovery had ended and that initial, answering, and rebuttal testimony had been filed on the issue of the proper demand cost allocator methodology prior to the suspension of the procedural schedule in that proceeding. Therefore, the Presiding Judge ordered the participants to resubmit the testimony proffered in Docket No. ER06-274-003, after redacting all testimony not dealing with the demand cost allocator issue.

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[16] *Southwestern Pub. Serv. Co.*, 124 FERC ¶ 61,232 at P 5. Under section II.B.3 of the PNM Settlement Agreement, SPS is required to submit a compliance filing within 30 days of the date on which the wholesale partial requirements rates are determined in the instant docket. *Id.* P 6.

[17] The Commission approved the December 2007 Settlement Agreement on April 21, 2008. *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,054 (2008).

[18] *Southwestern Pub. Serv. Co.*, Docket No. ER06-274-007 (Feb. 19, 2008).

9. In total, the parties submitted testimony from five witnesses on the demand cost allocation issue and that testimony included detailed load data for the SPS system.[19] Much of the testimony focused on the results of the three separate peak load tests, explained in detail below, that the Commission has traditionally used to determine the appropriate demand cost allocator for a utility. In short, the witnesses for SPS and the New Mexico Cooperatives testified that all three peak load tests indicate that a 12 CP demand allocator is appropriate, while Golden Spread's witness testified that one of the tests indicates that SPS is a 3 CP utility and the other two tests produce "borderline" 12 CP results but are very close to the results these tests produced in Opinion No. 162, the 1983 rate case in which the Commission initially found SPS to be a 3 CP utility.[20] A key difference between the witnesses' test results was the treatment of SPS's sales to El Paso Electric Company (EPE) and PNM. SPS's witnesses included the sales to EPE and PNM in their load calculations, whereas Golden Spread's witnesses excluded those sales.

10. On June 12, 2008, SPS filed a motion for summary disposition on the appropriate demand cost allocator methodology for the Locked-In Period.[21] The Presiding Judge initially denied SPS's motion after erroneously construing it as a motion to dismiss.[22] SPS filed a motion for reconsideration of that decision, which the Presiding Judge granted on June 18, 2008.

11. In the motion for summary disposition, SPS argued, in pertinent part, that the Commission had determined in the rate cases immediately before and after the Locked-In Period—Opinion No. 501 and Docket No. ER08-749-000, respectively—that SPS was a 12 CP utility, and that the three peak load tests support the same determination for the Locked-In Period.[23] SPS also replicated a table that the Commission used in Opinion

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[19] In analyzing SPS's load characteristics for the Locked-In Period, the witnesses used 2005-2006 data. However, the parties used actual data for certain months and projected data for the other months of the year. To compute the projected data, some of the parties used SPS's historical data from years 2000-2006. In analyzing demand allocation, the Commission typically uses data from more than one year to account for anomalous demand that may occur due to unseasonable weather or unusual system conditions.

[20] Ex. GSE-40 at 11.

[21] SPS June 12, 2008 Motion for Summary Disposition.

[22] *Southwestern Pub. Serv. Co.*, Docket No. ER06-274-007 (Jun. 13, 2008).

[23] SPS June 12, 2008 Motion for Summary Disposition at 4.

No. 501 to illustrate the results of the peak load tests, but SPS expanded upon that table by including the results of each witness in the instant proceeding.[24]

12. Cap Rock, New Mexico Cooperatives, and Trial Staff all filed answers supporting SPS's motion for summary disposition. Golden Spread submitted an answer on July 3, 2008 opposing SPS's motion for summary disposition. Golden Spread's July 3, 2008 answer also included a cross-motion to hold the hearing in abeyance pending the outcome of rehearing requests on Opinion No. 501. SPS and Cap Rock filed answers opposing Golden Spread's motion to hold the case in abeyance on July 9, 2008 and July 18, 2008, respectively. As discussed below, the Presiding Judge issued the Initial Decision granting SPS's motion for summary disposition while Opinion No. 501 was still pending rehearing.[25] In granting the motion, the Presiding Judge relied, in part, on the Commission's determination in the immediately preceding SPS rate case, the Opinion No. 501 proceeding.

[24] The table from Opinion No. 501 and SPS's expanded version of that table are presented here:

Opinion No. 501 Chart	Lowest-To-Peak	On-Peak-Off-Peak	Average-To-Peak
Historical Commission Range for 12 CP	66% or higher	19% or less	81% or higher
Heintz, SPS-37 at 16	68%	19%	82%
Saffer FRC-2 Pro Forma	70%	18%	84%
Linxwiler, GSL – 1 at 9-1-10	67.55%	19%	82.05%
Diller, CRE-1 at 18	70%	18%	84%

Expanded Chart			
Hudson, SPS-4	68%	19%	83%
Heintz, SPS-63	69%	19%	83%
Saffer, NMC-2	70%	18%	84%
Linxwiler, GSE-50	68% - 69%	19% - 20%	82-83%

Id. at 6. As discussed in detail below, the data SPS presented from Mr. Linxwiler's testimony includes SPS's off-system sales to EPE and PNM, which Mr. Linxwiler argued should be excluded.

[25] Initial Decision, 124 FERC ¶ 63,015 (2008) (issued August 29, 2008).

B. Opinion No. 501 Proceeding

13. On November 2, 2004, just over one year before SPS commenced the instant proceeding, Golden Spread, Lyntegar Electric Cooperative, Inc. (Lyntegar), and the New Mexico Cooperatives, filed a complaint in Docket No. EL05-19-000 alleging that SPS was violating the Commission's fuel cost adjustment clause (FCAC) regulations and the FCAC provisions of its wholesale customers' rate schedules.[26] On the same day that the complaint was filed, SPS also filed, in Docket No. ER05-168-000, proposed revisions to its FCAC and power supply contracts, contending that such revisions were necessary to conform to the Commission's current fuel cost and purchased economic power adjustment clause regulations.[27] Docket Nos. EL05-19-000 and ER05-168-000 were subsequently consolidated and set for hearing.[28]

14. A hearing was conducted in Docket Nos. EL05-19-002 and ER05-168-001 at which SPS argued that a 12 CP demand allocator was appropriate for the locked-in period from January 1, 2005 through June 30, 2006, despite the fact that SPS had historically used a 3 CP demand allocator. On May 24, 2006, the Administrative Law Judge in that proceeding issued an initial decision ordering SPS to continue using a 3 CP demand allocation methodology.[29] Between July and November of 2007 the parties filed three motions requesting that the Commission withhold action on the initial decision pending the outcome of settlement discussions. The Commission granted the motions.

15. As mentioned above, on December 3, 2007, SPS filed the December 2007 Settlement Agreement on behalf of itself, Golden Spread, Lyntegar, and Occidental in Docket Nos. EL05-19-000, ER05-168-000, and ER06-274-000. The December 2007 Settlement Agreement resolved, among those four parties, all issues except the appropriate demand cost allocator for the SPS system. The Commission approved the December 2007 Settlement Agreement on April 21, 2008.[30]

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[26] Complaint, Docket No. EL05-19-000 (filed Nov. 2, 2004).

[27] SPS Tariff Filing, Docket No. ER05-168-000 (filed Nov. 2, 2004).

[28] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004) (Opinion No. 501 Hearing Order).

[29] *Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co.*, 115 FERC ¶ 63,043, at 65,174 (2006).

[30] *Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,054 (2008).

16. Also on April 21, 2008, the Commission issued its order on initial decision – Opinion No. 501– in which it overruled the Administrative Law Judge on the issue of the appropriate demand cost allocator.[31] The Commission found that SPS demonstrated load profile changes warranting a determination that a 12 CP demand allocation methodology was appropriate for the locked-in period in that proceeding. Several parties filed requests for rehearing and clarification of Opinion No. 501.

17. Between June 2009 and June 2010, the parties submitted 10 motions requesting that the Commission defer action on the requests to accommodate the ongoing settlement negotiations in the Opinion No. 501 proceeding. Those settlement negotiations yielded two additional settlement agreements in January 2010 and July 2010 that resolved all issues in the Opinion No. 501 proceeding among SPS, Occidental, Cap Rock, and the New Mexico Cooperatives. Concurrent with the instant order, the Commission, in a separate order, grants in part and denies in part the remaining requests for rehearing and clarification of Opinion No. 501.[32] However, as mentioned above, the Presiding Judge in the instant proceeding issued the Initial Decision while the rehearing requests were pending in the Opinion No. 501 proceeding.

C. <u>ER08-749-000 Proceeding</u>

18. In addition to the Opinion No. 501 proceeding, the Initial Decision also relied upon the Commission's determination on the demand cost allocation issue in the SPS rate case immediately following the instant rate case. On March 31, 2008, almost five months before the Presiding Judge issued the Initial Decision in the instant proceeding, SPS filed additional changes to the rates and rate design applicable to its wholesale full requirements customers.[33] SPS filed the rates using a 3 CP demand cost allocator, but agreed to use a 12 CP demand cost allocator, instead, if the Commission suspended the rates for only a nominal period.[34] On May 30, 2008, the Commission conditionally accepted SPS's proposed rates for filing using the 12 CP demand cost allocator, suspended the rates for a nominal period, to become effective June 1, 2008, subject to

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[31] *Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co.*, Opinion No. 501, 123 FERC ¶ 61,047, at 61,249 (2008).

[32] *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*, Opinion No. 501-A, 144 FERC ¶ 61,132 (2013).

[33] SPS, Transmittal, Docket No. ER08-749-000 (filed Mar. 31, 2008).

[34] *Id.* at 4-5.

refund, and established hearing and settlement judge procedures in Docket No. ER08-749-000.[35]

II. Substantive Matters

A. Initial Decision

19. On August 29, 2008, the Presiding Judge granted SPS's motion for summary disposition in the instant proceeding, finding that there was no genuine issue of material fact in dispute. The Presiding Judge found that, based on the record as a whole, it was reasonable to conclude that a 12 CP demand allocation methodology was appropriate for the Locked-In Period.

20. The Presiding Judge explained that the Commission had found, "on essentially the same evidence in this case," that a 12 CP demand allocator was appropriate for the SPS system immediately before and after the Locked-In Period, in Opinion No. 501 and Docket No. ER08-749-000. The Presiding Judge explained that the doctrine of the law of the case precludes a lower decisional authority from reconsidering an issue already decided by a higher decisional authority and that the doctrine applied under these circumstances. Accordingly, the Presiding Judge concluded that the Commission had already found that the 12 CP demand cost allocator was appropriate for SPS.

21. The Presiding Judge found SPS's expanded version of the Opinion No. 501 peak load test table to be "an especially important piece of evidence in this case." The Presiding Judge explained that the Commission used the same analytical criteria for the table in Opinion No. 501 that it used in earlier proceedings – Opinion Nos. 162[36] and 337[37] – in which the Commission found a 3 CP demand allocator to be appropriate for SPS. The Presiding Judge explained that SPS's expanded table, which applied the same analytical criteria from Opinion No. 501 to the evidence submitted in this case, shows that SPS has continued to be a 12 CP utility since the locked-in period in Opinion No. 501.

22. The Presiding Judge rejected Golden Spread's argument that the relevance of Opinion No. 501 is lessened by the fact that it does not take into account evidence of

[35] Docket No. ER08-749-000 Hearing Order, 123 FERC ¶ 61,225.

[36] *Southwestern Pub. Serv. Co.*, Opinion No. 162, 22 FERC ¶ 61,341 (1983).

[37] *Southwestern Pub. Serv. Co.*, Opinion No. 337, 49 FERC ¶ 61,296 (1989), *reh'g denied*, Opinion No. 337-A, 51 FERC ¶ 61,341 (1990) (Opinion No. 337) (affirming the ALJ's decision that SPS remained a 3 CP utility).

recent changes on the SPS system. The Presiding Judge explained that, to the extent Golden Spread was referring to evidence more recent than the parties' written filings in this proceeding, Golden Spread's argument was unavailing. The Presiding Judge stated that, after Golden Spread had agreed in the December 2007 Settlement Agreement that discovery had ended, the written testimony had been re-filed and that testimony contained nothing that lessened the relevance of Opinion No. 501.

23. The Presiding Judge also rejected Golden Spread's argument that the elapsed time between the test periods in Opinion No. 501 and the instant proceeding supports denying SPS's motion for summary disposition. The Presiding Judge explained that unlike in *Illinois Power*,[38] where the test periods were four years apart, the test periods in Opinion No. 501 and the instant proceeding are closer in time – two years apart. The Presiding Judge explained further that Golden Spread had the opportunity to submit more recent data in this proceeding than it submitted in the Opinion No. 501 proceeding, and the new data does not show that anything "extraordinary" happened during the Locked-In Period that would render the determinations in Opinion No. 501 less controlling. The Presiding Judge concluded that no genuine issue of material fact existed and that the record, taken as a whole, led to the reasonable conclusion that SPS was a 12 CP utility for the Locked-In Period.

B. Briefs

1. Briefs on Exceptions

24. Golden Spread excepts to the Initial Decision based on four alleged legal errors and their associated policy considerations.[39]

25. First, Golden Spread argues that the Initial Decision misapplies the doctrine of the law of the case. According to Golden Spread, that doctrine serves only to preclude reconsideration of "the *same issue* in the *same case* by the *same court*."[40] Golden Spread argues that the Initial Decision improperly expands the doctrine by concluding that the resolution of the same issue in a different case must lead to the same result on that issue

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[38] *Illinois Power Co.*, 59 FPC 2245 (1977), *reh'g denied*, 1 FERC ¶ 61,174 (1977).

[39] Golden Spread Sept. 29, 2008 Brief on Exceptions at 6.

[40] *Id.* at 11 (emphasis in original) (citing *Williamsburg Wax Museum, Inc. v. Historic Figures, Inc.*, 810 F.2d 243, 250 (D.C. Cir. 1987); *Kimberlin v. Quinlan*, 199 F.3d 496, 500 (D.C. Cir. 1999); *Florida Gas Transmission Co.*, 41 FERC ¶ 61,122, at 61,302 n.10-11 (1987); *Storey Oil Co., Inc.*, 71 FERC ¶ 63,010, at 65,074 (1995), *errata*, 72 FERC ¶ 63,015 (1995)).

in the instant case. Golden Spread alleges that the Initial Decision's reliance on *FPL Energy*[41] is misplaced because that decision concerned the impact of a "prior *final order*"[42] in "the *same proceeding*."[43] Golden Spread explains that the Initial Decision circumvented the same case requirement by focusing on the similarity of the evidence presented in the instant proceeding and in the Opinion No. 501 proceeding. Golden Spread avers that this is improper because the same issue can be considered in a new rate proceeding, despite alleged factual similarities between the two proceedings. Golden Spread further explains that the Initial Decision's interpretation of the law of the case doctrine is at odds with the Commission's decision in Opinion No. 501 that the demand cost allocation methodology must be decided on a case-by-case basis.[44]

26. Golden Spread also argues that, even if the law of the case doctrine could be used to preclude consideration of the same issue in a different proceeding, it cannot be used in this particular proceeding because the two cases relied on to establish the law of the case – Opinion No. 501 and the Docket No. ER08-749-000 Hearing Order – were both pending rehearing when the Presiding Judge invoked them. Golden Spread contends that orders pending rehearing cannot be used to establish the law of the case.[45] Furthermore, Golden Spread asserts that relying on the non-final Opinion No. 501 is inappropriate for the additional reason that the Commission's determination was based on incorrect references to record evidence. Golden Spread states that a proper consideration of the evidence on rehearing in that proceeding will justify a 3 CP demand cost allocator.

27. As to the second alleged legal error, Golden Spread contends that summary disposition was improper because the Initial Decision erroneously concluded that no genuine issues of fact exist. Golden Spread contends that it was not given the opportunity to present all the facts that could have produced a contrary result. Golden Spread asserts that the Initial Decision relies entirely on the expanded table in SPS's motion for summary disposition, which is improper because neither arguments advanced by counsel, nor tables prepared by counsel can be relied upon as evidence in a

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[41] *Electric Utilities – FPL Energy Marcus Hook, L.P. v. PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,289 (2008) (*FPL Energy*).

[42] Golden Spread Sept. 29, 2008 Brief on Exceptions at 13 (emphasis in original).

[43] *Id.* at 14 (emphasis in original).

[44] *Id.* (citing Opinion No. 501, 123 FERC at 61,249).

[45] Golden Spread Sept. 29, 2008 Brief on Exceptions at 15 (citing *Tarpon Transmission Co.*, 42 FERC ¶ 61,188, at 61,665 (1988)).

proceeding.[46] Accordingly, Golden Spread asserts that the expanded table is not evidence in this proceeding, and the Presiding Judge in the Initial Decision erred by treating it as such. Further, Golden Spread states that SPS's expanded table omits data and studies presented by Mr. Linxwiler. Moreover, even if the chart was properly considered evidence, Golden Spread contends that it should have the right to make an objection, submit rebuttal evidence, and cross-examine the witness that presented the table.[47]

28. Golden Spread contends that the Initial Decision erred in concluding that the evidence presented in the instant proceeding is essentially the same as the evidence presented in Opinion No. 501 and Docket No. ER08-749-000.[48] In addition, Golden Spread asserts that the perceived similarity of evidence in the three proceedings provided insufficient grounds for the Presiding Judge to conclude summarily that SPS was a 12 CP utility. Golden Spread states that, in actuality, the facts of the instant proceeding are significantly different from those in Opinion No. 501 and Docket No. ER08-749-000, and that the summary disposition improperly foreclosed Golden Spread's opportunity to present evidence of these changes on the SPS system.[49]

29. As to the third alleged legal error, Golden Spread argues that the Initial Decision misconstrued the December 2007 Settlement Agreement by indicating that it precluded the introduction of additional evidence at hearing.[50] Golden Spread contends that the Initial Decision erroneously concluded, based on a misreading of the December 2007 Settlement Agreement, that no genuine issues of fact existed that would lessen the relevance of Opinion No. 501. Golden Spread states that such issues of fact do exist and the December 2007 Settlement Agreement merely referenced the fact that the prefiled testimony stage of the proceeding was complete, not that the parties agreed to a paper hearing based solely on that prefiled testimony.[51] Golden Spread argues that the Presiding Judge's interpretation of the December 2007 Settlement Agreement deprived Golden Spread of its right to present necessary evidence and conduct cross-examination.

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[46] *Id.* at 21.

[47] *Id.* at 21-22.

[48] *Id.* at 23.

[49] *Id.* at 26.

[50] *Id.* at 27.

[51] *Id.* at 28.

30. As to the fourth alleged legal error, Golden Spread argues that the Initial Decision acknowledged the importance of establishing the demand cost allocator on a case-by-case basis but then erred by not doing so in this instance.[52] Golden Spread contends that the Initial Decision ignored the Commission precedent from *Illinois Power*,[53] which precludes summary disposition when the underlying facts may differ due to a difference in test periods.[54] Golden Spread asserts that the difference in test periods for Opinion No. 501 and the instant proceeding might, by itself, warrant different demand cost allocators, but that the Initial Decision arbitrarily distinguished the instant proceeding from *Illinois Power* based on the elapsed time between the test periods in each case.[55]

2. <u>Briefs Opposing Exceptions</u>

31. SPS, Cap Rock, Trial Staff, and the New Mexico Cooperatives (collectively, Respondents) all filed separate briefs opposing Golden Spread's exceptions to the Initial Decision. As an initial matter, the Respondents assert that Golden Spread has not raised any policy considerations that warrant Commission review of the Initial Decision.[56]

32. The Respondents disagree with Golden Spread regarding the Presiding Judge's application of the law of the case doctrine to this proceeding. SPS argues that the policy behind the law of the case doctrine applies here, because the Commission has a policy against relitigation of issues absent a showing that circumstances have changed significantly.[57] SPS contends that this policy is applicable in the instant proceeding because the Commission decided the demand allocation issue in Opinion No. 501 based on virtually the same facts presented in the instant docket.[58] According to Cap Rock and the New Mexico Cooperatives, the Presiding Judge did not rely solely on the law of the case doctrine, but instead looked at the entire record and granted summary disposition

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[52] *Id.* at 29-30.

[53] *Illinois Power Co.*, 59 FPC 2245, *reh'g denied*, 1 FERC ¶ 61,174.

[54] Golden Spread Sept. 29, 2008 Brief on Exceptions at 30.

[55] *Id.* at 31.

[56] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 4; Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 13-15; Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 11-12; SPS Oct. 20, 2008 Brief Opposing Exceptions at 4-5.

[57] SPS Oct. 20, 2008 Brief Opposing Exceptions at 5-6.

[58] *Id.* at 5.

pursuant to Rule 217 of the Commission's Rules of Practice and Procedure.[59] Trial Staff contends that the Presiding Judge appropriately applied the doctrine because the Commission is a "higher decisional authority" that has already resolved this issue in Opinion No. 501 and Docket No. ER08-749-000.[60] The New Mexico Cooperatives argue that Golden Spread has undermined its own arguments by conceding that the Commission's prior determination on the demand cost allocator should control absent subsequent facts showing a significant change in circumstances. According to the New Mexico Cooperatives, the Initial Decision properly concluded that the evidence does not reveal any such change.[61]

33. The Respondents assert that the Presiding Judge correctly found that no genuine issues of material fact exist and, therefore, appropriately granted summary disposition.[62] The Respondents claim that Golden Spread had sufficient opportunity to present its arguments and factual support. SPS claims that Golden Spread has not been deprived of any procedural rights.[63] Cap Rock posits that Golden Spread's grievance that it was denied the chance to cross-examine witnesses does not, by itself, provide a right to a hearing.[64] Similarly, Trial Staff argues that Rule 505 of the Commission's Rules of Practice and Procedure does not provide an absolute right to cross-examination.[65] The New Mexico Cooperatives assert that Golden Spread was provided ample opportunity to rebut and cross-examine the evidence in SPS's expanded chart, and that Golden Spread's claim concerning its opportunity for cross-examination is irrelevant due to the limitations included in the Order Establishing Hearing Schedule and the Presiding Judge's Rules for Conduct of Hearings.[66] The New Mexico Cooperatives also reject Golden Spread's argument that it was deprived of the opportunity to present post-test year data, stating that

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[59] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 13; New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 4-5.

[60] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 18.

[61] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 8.

[62] *Id.* at 9; Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 25; Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 13; SPS Oct. 20, 2008 Brief Opposing Exceptions at 6.

[63] SPS Oct. 20, 2008 Brief Opposing Exceptions at 10.

[64] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 16-17.

[65] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 28.

[66] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 12-13.

this argument is contrary to Commission precedent and to Golden Spread's own arguments in the Opinion No. 501 proceeding.[67] The New Mexico Cooperatives contend that Golden Spread's view of cross-examination would be contrary to Commission policy and would nullify Rule 217.[68]

34. With regard to the evidentiary record, the Respondents reject Golden Spread's characterization of SPS's expanded table as mere argumentation, rather than evidence.[69] SPS further contends that Golden Spread's characterization of the expanded table is inaccurate and misleading. SPS explains that all relevant pre-filed written testimony was submitted to the Presiding Judge and, because the 2006 test period has passed, there is no new evidence for Golden Spread to present at an evidentiary hearing.[70] SPS further contends that any differences in the data between the Opinion No. 501 test year and the test year in the instant case are non-material.[71] SPS also disagrees with Golden Spread's argument that future changes to the SPS system necessitate a full evidentiary hearing. According to SPS, any such future changes are irrelevant because this case involves a locked-in period.[72]

35. Cap Rock argues that Golden Spread has failed to show that summary disposition was inappropriate or that the Presiding Judge's determination regarding SPS's demand cost allocator was wrong. Cap Rock contends that the Presiding Judge correctly found that no genuine issue of material fact exists because the parties' evidence shows nearly identical peak load test ratios applicable to the SPS system, and those ratios support a 12 CP methodology.[73] Cap Rock asserts that, contrary to Golden Spread's claims, there is no indication that the Presiding Judge failed to view the evidence in the light most favorable to Golden Spread.[74] Cap Rock contends that Golden Spread has failed to show

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[67] *Id.* at 13-14.

[68] *Id.* at 14-15.

[69] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 11; Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 26-28; Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 15-16; SPS Oct. 20, 2008 Brief Opposing Exceptions at 8-9.

[70] SPS Oct. 20, 2008 Brief Opposing Exceptions at 9.

[71] *Id.*

[72] *Id.* at 11.

[73] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 14.

[74] *Id.* at 15.

that the expanded table submitted by SPS contained any factual errors or that the Presiding Judge relied on it for anything but a summary of the parties' positions.[75]

36. The New Mexico Cooperatives state that no genuine issue of fact exists regarding the ratios submitted in the witnesses' testimonies nor is there a genuine issue of fact that the ratios fall within the range that Opinion No. 501 determined was indicative of a 12 CP utility. The New Mexico Cooperatives argue that, under Golden Spread's approach, summary disposition would never be appropriate and a hearing, including cross-examination, would always be required regardless of whether genuine issues of fact exist.[76]

37. Trial Staff contends that SPS's expanded table was properly considered as evidence and, even if that were not the case, all of the information in SPS's expanded table is still in the record as evidence in this proceeding.[77] Trial Staff asserts that the Initial Decision correctly concluded that Docket Nos. EL05-19 and ER08-749 are based on essentially the same evidence as the instant proceeding. Trial Staff explains that the new data that Golden Spread claims it was precluded from submitting are irrelevant to the locked-in period in this proceeding, even though these data might be relevant to the proceeding in Docket No. ER08-749.[78]

38. Some of the parties disagree with Golden Spread regarding the impact of the December 2007 Settlement Agreement on the hearing, and the Initial Decision's treatment of that settlement.[79] The New Mexico Cooperatives argue that Golden Spread ignores the fact that the December 2007 Settlement Agreement precluded the submittal of additional evidence on the demand cost allocator issue in this proceeding. According to the New Mexico Cooperatives, the December 2007 Settlement Agreement preserved the settling parties' right to make legal arguments on the issue, but not to submit new facts and evidence into the record.[80] Trial Staff asserts that Golden Spread misconstrues the Initial Decision's interpretation of the December 2007 Settlement Agreement. According to Trial Staff, the Presiding Judge simply described the December 2007 Settlement

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[75] *Id.* at 15-16.

[76] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 14.

[77] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 27.

[78] *Id.* at 30.

[79] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 15-16; Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 31-32.

[80] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 16.

Agreement and its effect on the relevance of Opinion No. 501, but the Presiding Judge did not imply that the agreement had any effect on the parties' cross-examination rights in the instant proceeding.[81]

39. Some parties refute Golden Spread's argument that the Presiding Judge did not conduct a case-by-case analysis to determine SPS's demand cost allocator for the Locked-In Period.[82] Cap Rock asserts that there is no Commission precedent requiring the Presiding Judge to ignore the Commission's orders immediately before and after the Locked-In Period.[83] Cap Rock points out that Golden Spread has argued that such decisions should be a factor in resolving the demand allocation methodology.[84] SPS contends that Golden Spread had the opportunity to present more recent data to inform the case-by-case analysis in this proceeding, but that Golden Spread presented no evidence showing a change in the relevant circumstances between the test period in Opinion No. 501 and the test period in the instant case. SPS concludes that the lack of evidence showing changed circumstances justified the summary disposition.[85]

40. The Respondents disagree with Golden Spread's contention that Opinion No. 501 and the Docket No. ER08-749-000 Hearing Order are not final orders and thus cannot be relied upon as the basis for granting summary disposition.[86] The Respondents assert that the Commission and the Presiding Judge may rely on those orders despite the pending rehearing requests and possibility of appeal. Cap Rock, Trial Staff, and the New Mexico Cooperatives point out that, in Docket No. ER08-749, the Commission has already rejected Golden Spread's argument regarding the precedential effect of Opinion No. 501 and Docket No. ER08-749.[87] SPS asserts that the Commission has explained that it may

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[81] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 31.

[82] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 17; SPS Oct. 20, 2008 Brief Opposing Exceptions at 12-13.

[83] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 17.

[84] *Id.*

[85] *Id.* at 13.

[86] New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 16-17; Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 33; Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 19-20; SPS Oct. 20, 2008 Brief Opposing Exceptions at 13.

[87] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 33; Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 20; New Mexico Cooperatives Oct. 20, 2008 Brief Opposing Exceptions at 16-17.

rely on contested orders as final Commission orders, despite pending rehearing requests or appeals, unless they have been stayed.[88] Cap Rock contends that a Commission order becomes final when it "imposes an obligation, denies a right, or fixes some legal relationship as a consummation of the administrative process[,]"[89] and that both Opinion No. 501 and the Docket No. ER08-749-000 Hearing Order qualify as final orders. Furthermore, Cap Rock contends that Golden Spread's argument, if successful, would allow utilities to ignore a Commission order until it is no longer subject to judicial review.[90]

41. Cap Rock disagrees with Golden Spread's claim that the Initial Decision allowed SPS to avoid its obligation under FPA section 205 to show that the 12 CP demand allocation methodology is just and reasonable.[91] Cap Rock states that SPS met this burden through its motion for summary disposition and witness testimony. Trial Staff argues that the Commission's review of the Initial Decision must simply address whether the record would lead a reasonable trier of facts to find no material issues of disputed fact.[92] Trial Staff contends that the Presiding Judge's ruling was not arbitrary and was supported by Commission precedent. Trial Staff also argues that a difference in test periods between two proceedings could warrant different demand allocator determinations, but such a result is not automatic, and the Presiding Judge reasonably found that different determinations were not warranted in this instance.[93]

C. Commission Determination

42. Because the Commission is reversing the demand cost allocator determination in Opinion No. 501 in an order being issued concurrently,[94] we will not rule on the Presiding Judge's grant of summary disposition. However, in light of the outcome in Opinion No. 501-A, we will make a determination on the appropriate demand cost allocation methodology for the SPS system based on the record in this proceeding. In

[88] SPS Oct. 20, 2008 Brief Opposing Exceptions at 13-14.

[89] Cap Rock Oct. 20, 2008 Brief Opposing Exceptions at 19.

[90] *Id.* at 20.

[91] *Id.* at 18.

[92] Trial Staff Oct. 20, 2008 Brief Opposing Exceptions at 17.

[93] *Id.* at 32-33.

[94] Opinion No. 501-A, 144 FERC ¶ 61,132.

doing so, we find that a 3 CP demand cost allocation methodology is appropriate for the SPS system during the Locked-In Period.

43. The Commission has stated that in selecting the proper demand cost allocation methodology, the full range of a utility's operating realities should be considered, including system demand and off-system sales commitments.[95] In the instant proceeding, the parties submitted their initial, rebuttal, and answering testimony on the demand allocation issue, and no party sought reconsideration of the Presiding Judge's Scheduling Order requiring the parties to re-submit that same testimony more than two years after the 2005-2006 test year. Therefore, we conclude that the record contains sufficient information for us to resolve the demand cost allocation issue.

44. We agree with Golden Spread that SPS's sales to EPE and PNM were off-system opportunity sales that should be excluded from the load ratio calculations for the SPS system. The sales at issue in the instant case are very similar to those the Commission found to be off-system opportunity sales in Opinion No. 501.[96] As with the off-system sales in Opinion No. 501, the record in this proceeding does not indicate that SPS planned for and constructed its system, or made purchases, to facilitate the sales to EPE and PNM. SPS's sales to EPE and PNM were market-based opportunity sales to customers outside SPS's control area that have a lower curtailment priority than SPS's native load customers.[97] Further, the PNM sale at issue was transacted at a time when SPS had surplus capacity.[98] Including these off-system opportunity sales in the peak load tests would impermissibly skew the test results. Therefore, we find that SPS's sales to EPE and PNM should be excluded from SPS's load calculations when determining the appropriate demand cost allocator for the Locked-In Period. As explained below, analyzing SPS's system demand, after excluding the off-system sales to EPE and PNM, indicates that SPS remains a 3 CP utility.

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[95] *Carolina Power*, 4 FERC ¶ 61,107, at 61,230 (1978); *Illinois Power Co.*, 11 FERC ¶ 63,040, at 65,248-49 (1980) (*Illinois Power Initial Decision*), *aff'd*, 15 FERC ¶ 61,050 (1981). *See also* Opinion No. 501-A, 144 FERC ¶ 61,132 at P 52 (explaining that excluding off-system opportunity sales for which SPS does not plan its system is consistent with the principle of cost-causation, which requires that the parties who cause the costs should bear the costs (citing *Cincinnati Gas & Electric Co.,* 71 FERC ¶ 61,380, at 62,478 n.30 (1995)).

[96] Ex. GSE-1 at 26.

[97] Ex. SPS-47 at 9-12.

[98] Ex. GSE-1 at 25.

45. The Commission has stated that substantive ratemaking principles, such as demand allocation, once established for a particular company, should continue to be applied in subsequent cases unless there is a supervening change in circumstances or Commission policy requiring a different conclusion.[99] In each of SPS's last three rate cases—Opinion No. 162, in 1983;[100] Opinion No. 337, in 1989;[101] and Opinion No. 501-A, issued concurrently with this order[102]—the Commission determined that SPS was a summer peaking utility for which a 3 CP demand cost allocation methodology was appropriate. Conducting a comparable analysis in the instant proceeding indicates there has been no supervening change in circumstances or Commission policy that warrants a change in SPS's demand cost allocator for the Locked-In Period.

46. The Commission has historically focused on three separate peak load tests when analyzing the demand cost allocation methodology appropriate for a given utility. The first test is the On and Off Peak Test, whereby the Commission compares the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak.[103] The second test is the Low to Annual Peak Test, in which the Commission calculates the lowest monthly peak as a percentage of the annual peak.[104] The third test is

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[99] *Louisiana Power & Light Company*, Opinion No. 110, 14 FERC ¶ 61,075, at 61,128 (1981).

[100] Opinion No. 162, 22 FERC ¶ 61,341 (1983).

[101] *Southwestern Pub. Serv. Co.*, Opinion No. 337, 49 FERC ¶ 61,296 (1989).

[102] Opinion No. 501-A, 144 FERC ¶ 61,132.

[103] Under this test, the Commission has held that, in general, a 19 percentage point or less difference between these two figures indicates using the 12 CP demand allocation methodology is appropriate. *See Illinois Power Initial Decision*, 11 FERC at 65,248-49 (comparing average summer peak of 94 percent of annual peak to eight-month average peak of 75 percent of annual peak, a difference of 19 percentage points).

[104] Under this test, the Commission has held that a range of 66 percent or higher is indicative of a 12 CP system. *See id.* (approving 12 CP where lowest monthly peak as percentage of annual peak was 66 percent); *Delmarva Power & Light Co.*, 17 FERC ¶ 63,044, at 65,201 (1981) (*Delmarva Initial Decision*), *aff'd*, Opinion No. 185, 24 FERC ¶ 61,199 (1983), *reh'g denied*, Opinion No. 185-A, 24 FERC ¶ 61,380 (1983) (stating that for the Low to Annual Peak test, a low percentage indicates a load curve with a clearly defined peak, while a high percentage indicates a flatter load curve).

the Average to Annual Peak Test, whereby the Commission computes the average of the 12 monthly peaks as a percentage of the annual peak.[105] Commission precedent has set certain benchmarks against which the results of these tests are compared to help determine the appropriate demand allocation for a particular utility.[106]

47. When comparing the results of the three peak load tests in this proceeding (calculated without SPS's sales to EPE and PNM) to the benchmarks established by the Commission in prior cases, one test – the On and Off Peak Test – indicates that SPS is a 3 CP utility; one test – the Low to Annual Peak Test – indicates that SPS is a 12 CP utility; and one test – the Average to Annual Peak Test – barely leans toward a 12 CP demand allocator. The table below reflects the results of these peak load tests calculated using SPS's load data for 2001 through 2006, excluding the off-system sales.[107]

	Low to Annual Peak	On and Off Peak	Average to Annual Peak
Historical Commission Minimum for 12 CP	66% or higher	19% or less	81% or higher
2001	69.07	22.14	80.22
2002	67.14	21.36	81.2
2003	65.56	19.43	79.59

[105] Under this test, the Commission has held that the range indicating whether a utility is to be considered a 12 CP system is 81 percent or higher. *See Illinois Power Initial Decision*, 11 FERC at 65,249 (approving 12 CP where average monthly peak for five-year period was 81 percent); *Lockhart Power Co.*, Opinion No. 29, 4 FERC ¶ 61,337, at 61,807 (1978) (approving 12 CP where average monthly demand was 84 percent of annual system peak); *El Paso Elec. Co.*, Opinion No. 109, 14 FERC ¶ 61,082, at 61,147 (1981) (approving 12 CP where twelve-month average was 84 percent of maximum peak).

[106] *See supra* n.103, n.104, n.105.

[107] The Commission excluded from the chart load data from 2000 because that was an anomalous year on the SPS system. During that year, Golden Spread converted from full requirements to partial requirements service. Thus, a portion of the load data for 2000 reflects Golden Spread's full requirements service and is not representative of the demands placed on SPS's system during the locked-in period.

2004	67.13	22.89	80.47
2005	70.75	19.54	83.61
2006	68.99	20.98	82.31
Average 2001 - 2006	68.11	21.22	81.23

48. When the above results are compared to the results of the same peak load tests in Opinion Nos. 162 and 501-A, the numbers are not especially different—ranging less than two percentage points in each test. In all three cases, the test results are split, with at least one test indicating that a 3 CP demand cost allocator is appropriate and at least one test indicating that a 12 CP demand cost allocator is appropriate.

	Low to Annual Peak	On and Off Peak	Average to Annual Peak
Historical Commission Minimum for 12 CP	66% or higher	19% or less	81% or higher
Opinion No. 162	66.98	22.9	80.1
Opinion No. 501-A	66.2	21.7	79.9
Average 2001 -2006	68.11	21.22	81.23

49. The load ratios in the above tables indicate that SPS's system demand during the Locked-In Period is not significantly different from the system demand in SPS's past rate cases. In each of the rate cases, the results of the peak load tests are split, and all of them are close to the thresholds the Commission has historically used in applying these tests.

50. Because the results of the three primary peak load tests are not the only indicators of a change on SPS's system, we will also consider the two additional tests that the Commission conducted in Opinion No. 501-A. The first test measures the number of times the non-summer monthly peak demand exceeds the summer monthly peak

demand.[108] For SPS, the non-summer monthly peak demand was greater than the lowest summer peak month only one time during the period from 2001 to 2006.[109] The second test computes the number of times the non-summer monthly peak demand exceeds the summer monthly peak demand in the preceding year.[110] For SPS, the non-summer peak demand only twice exceeded the summer peak demand of a prior year over the period from 2001 to 2006.[111] Thus, the results of these two additional peak load tests tend to support the use of a 3 CP demand allocator for SPS. Notably, the results of these two tests point even more strongly towards a 3 CP demand allocator for the Locked-In Period than the same tests did in Opinion No. 501-A. The following table compares the results of these additional load tests in each proceeding.

	# of non-peak months greater than peak months	non-peak months exceeding prior year peak months
Opinion No. 501-A (Average of 2001 - 2004)	0.5 per year (3 CP)	1 per year (3 CP)
Docket No. ER06-274-000 (Average of 2001 - 2006)	0.17 per year (3 CP)	0.6 per year (3 CP)

51. As we explained above, the standard for changing a substantive ratemaking principle, such as the proper demand allocator, is that there must be a supervening change in circumstances or Commission policy to warrant a change. Here, we do not find a change in SPS's system demand significant enough to warrant changing to a 12 CP demand cost allocator. While the results of the peak load tests here have moved slightly toward a 12 CP demand allocator, one test still clearly supports a 3 CP demand allocator and the results of all three load tests are close to the results from Opinion Nos. 162 and 501-A, in each of which the Commission determined SPS was a 3 CP utility. In addition,

[108] Opinion No. 501-A, 144 FERC ¶ 61,132 at P 57; *Carolina Power & Light,* 4 FERC ¶ 61,107 (1978), *reh'g granted on other grounds*, 5 FERC ¶ 61,081 (1978)).

[109] *See* Ex. GSE-51.

[110] Opinion No. 501-A, 144 FERC ¶ 61,132 at P 57; *Consumers Energy Co.*, 86 FERC ¶ 63,004 (1999), *aff'd*, 98 FERC ¶ 61,333 (2002)).

[111] *See* Ex. GSE-51.

the two additional peak load tests we conducted both indicate, even more strongly than they did in Opinion No. 501-A, that SPS is a 3 CP utility.

52. We conclude that the corrected load data and the peak load tests, taken together, indicate that SPS is a 3 CP utility. However, system demand is only one of the operating realities the Commission must consider. We will also look at the other evidence the parties submitted concerning SPS's system, specifically SPS's scheduled maintenance and operating reserves during the test year.[112]

53. With regard to scheduled maintenance, the record demonstrates that during the 2005-2006 test year, SPS conducted no scheduled maintenance during June, July, and August; and between 2001-2006, SPS only once conducted scheduled maintenance in those three months.[113] While not conclusive, this is certainly more indicative of a 3 CP utility than a 12 CP utility. If summer were not a critical time for peak load, SPS would spread its system maintenance activities more evenly throughout the year. Similarly, with regard to operating reserves, the record shows that SPS's operating reserves, as a percentage of peak load, were consistently lower in the peak summer months than in the non-summer months.[114] During the 2001-2006 period, there were very few non-summer months in which the operating reserves dropped below the reserve level of a peak summer month.[115] The existence of lower operating reserves in the peak summer months indicates that SPS is generally more concerned with meeting its reserve margins in summer months than in non-summer months. Thus, as with the data concerning SPS's

[112] The Commission has, in the past, considered other operating realities; specifically, a utility's unscheduled outages and diversity. *E.g.*, Opinion No. 501-A, 144 FERC ¶ 61,132 at PP 60-61. We do not address unscheduled outages and diversity in the instant order because the record contains limited data on these considerations.

[113] Ex. GSE-51 at 1-6. The one instance of scheduled maintenance occurring in June, July, or August was in July of 2002.

[114] *Id.*

[115] In 2003, the reserve margins in May and September were lower than the reserve margin in June. *Id.* at 3. In 2005, the reserve margin in September was lower than the reserve margin in all three of the peak summer months. *Id.* at 5; *see also* Ex. SPS-64 at 2. In addition, the record contains conflicting data entries for 2006—the entry in Exhibit GSE-51 shows that the three peak summer months have the lowest reserve margins for that year, while the entry in Exhibit SPS-64 shows that the reserve margin in May was lower than the reserve margins in June and August. *Compare* Ex. GSE-51 at 6 *with* Exhibit SPS-64 at 3.

scheduled maintenance, the data on SPS's operating reserves are more indicative of a 3 CP utility than a 12 CP utility.

54. These operational realities, combined with the load ratio tests, demonstrate that SPS's load profile has not changed sufficiently to justify a change to a 12 CP demand cost allocator. Accordingly, we find that a 3 CP demand cost allocation methodology is appropriate for SPS during the Locked-In Period.

<u>The Commission orders</u>:

(A) The Initial Decision is hereby reversed, as discussed in the body of this order.

(B) SPS is hereby directed to file, within 30 days of the date of this order, a compliance filing quantifying refunds relating to cost of service rates from July 1, 2006 through June 30, 2008.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

D

Maritime Electric

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138 kV TRANSMISSION EXPANSION PLAN

FOR

LARGE SCALE WIND DEVELOPMENT ON PEI

October 2005

DRAFT

TABLE OF CONTENTS

APPENDICES

1. EXECUTIVE SUMMARY

This document describes the transmission system additions necessary to accommodate up to 150 MW of wind power in each of the western and eastern parts of PEI. Adding on an additional 50 MW of wind power development in the central part of the Island, it should be a relatively straightforward matter to accommodate up to 350 MW of wind power development on PEI.

Connecting this amount of wind power to the existing transmission system will require a significant investment in transmission infrastructure. Since this transmission infrastructure will probably be added over a period of years, it will be important to have at the outset an overall expansion plan, so that the transmission system will be expanded in a cost effective manner.

The starting point for the development of a transmission expansion plan is a listing of the areas where wind power development can be expected to occur. Given this listing, Maritime Electric has developed a 138 kV transmission expansion plan that will:

- Allow for the development of up to 350 MW of wind power. Significant further development will be much more expensive and may require the use of transmission voltages above 138 kV.
- Provide satisfactory system voltages over the expected range of normal operating conditions
- Provide satisfactory system voltages over a range of contingency operating conditions
- Provide a cost effective balance between initial capital costs for the infrastructure and the line losses over the 40 year expected life of the transmission infrastructure

The proposed transmission expansion plan should be taken as being somewhat indicative. While the actual details and sequence of expanding the transmission system will depend on where and when wind power is installed, the overall concept and estimated cost is expected to end up being much the same as described here.

The proposed transmission expansion plan can be implemented in stages to keep pace with installed wind power. The table below shows the estimated costs for the first stages of the expansion plan and the estimated total costs for the full implementation of the plan in the western and eastern parts of PEI. Allowing for 50 MW of development in the central part of PEI would bring the total estimated cost to approximately $30 million.

	Phase 1 Wind Power (MW)	Phase 1 Capital Cost ($ millions)	Full Plan Wind Power (MW)	Capital Cost for Full Plan ($ millions)
Western PEI	50	1.7	150	12.1
Eastern PEI	50	3.8	150	14.2

The proposed expansion plan is based on Maritime Electric financing and owning all transmission infrastructure up to the substations for the wind farms, including the metering equipment. The wind farm developers will own the substations that step the output from the wind farms up to transmission level voltages. This is expected to be the most equitable and efficient arrangement for all parties.

For reliability reasons it will be desirable at some point to expand the capacity of the interconnection between PEI and the mainland by installing a cable in the utility corridor of the Confederation Bridge. The estimated cost for this project is $30 million.

2. INTRODUCTION

The Government of PEI has stated its intention to see the wind resource on PEI developed on a large scale for the generation of electricity, with as much as several hundred megawatts of wind power installed on the Island.

The next page shows the existing Maritime Electric transmission system. Connecting several hundred megawatts of wind power to the existing system will require a significant investment in transmission infrastructure. The reason is that much of the wind resource is located at the extreme ends of the Island, where the transmission system is weakest.

Since this transmission infrastructure will probably be added over a period of years, it will be important to have at the outset an overall expansion plan, so that the transmission system will be expanded in a cost effective manner.

The starting point for the development of a transmission expansion plan is a listing of the areas where wind power development can be expected to occur. These are:

- The area to the north and west of Tignish, and down along the western shore as far south as West Cape.
- The area to the east of Malpeque Bay.
- The area to the north and east of Souris.

These three areas encompass most of what is considered to be the best wind resource. The associated transmission infrastructure that would be required for development in the western and eastern parts of PEI is the focus of this study because these are the areas that would require the most investment. The area to the east side of Malpeque Bay and other areas in the central part of PEI have not been considered here because the transmission infrastructure needed for their development would be much less. For example, the City of Summerside is considering a wind power development to the north of Summerside. This could easily be accommodated by the existing interconnection between the City and Maritime Electric if the City were to build a 69 kV line north from their substation.

Alternatively, Maritime Electric's transmission line T-5 could be tapped off near Slemon Park.

3. SYSTEM LOAD FORECAST

The study is based on a forecast system peak load for PEI of 250 MW for 2015.

The year 2015 was chosen because this is the year that the Renewable Energy Act requires the second phase renewable portfolio standard to become effective. A system peak load of 250 MW is based on the assumption that the PEI electricity load will continue to grow at close to the current rate, and takes into account the requirement in the Renewable Energy Act for utilities to reduce the intensity of the peak demand.

To simplify the analysis, no new load serving substations were added to the system. The loads at the existing substations were scaled up in proportion to the system load growth.

Load flows analyses were done for system peak load conditions and system minimum load conditions. A reason for analyzing system conditions at minimum load is to determine if voltage levels will be too high due to the capacitive charging effect of the approximately 240 km of on-Island 138 kV transmission lines that would be added to the system if the proposed transmission expansion plan were to be fully implemented. As well, minimum load is when there would be the largest requirement for exporting wind generation to the New Brunswick system.

4. DEVELOPMENT OF PLANNING CRITERIA

The main planning criteria required for the study are in connection with acceptable system voltage levels and cost of losses.

System voltages

Maximum and minimum acceptable voltages levels that are in keeping with good utility practice are as follows:

- For normal conditions, +5/-10 % of nominal for transmission buses and a minimum of 103% of nominal for distribution buses.
- For contingency conditions, +/-10% of nominal for transmission buses and a minimum of 100% of nominal for distribution buses. On an instantaneous basis a transmission bus can go as low as 85% of nominal.

The maximum allowable step change in voltage due to single contingencies is 10%.

Cost of losses

The cost of the losses in a transmission line over its expected 40 year operating life is an important consideration in determining the appropriate conductor size for the line. In addition to conductor loading, the following are the main factors that have been taken into consideration:

- Loss factors specific to wind generation were developed, because the output duration curve for a wind farm has a very different shape than the system load duration curve. For example, a wind farm can be expected to operate at rated output for approximately 10% of the hours in a year, whereas the system peak load occurs for just one hour of the year. Analysis of the North Cape Phase 1 wind farm hourly generation data indicates that the monthly loss factor is typically 11 percentage points less than the monthly capacity factor.
- Resistance values for transmission line conductors that take into account wind conditions and PEI temperatures were used. In particular, the cooling effect of the wind on the conductors increases significantly as wind speed, and hence wind generation increases. The resistance values that were used

are approximately 8% less than the values shown in handbooks for 25 deg C conductor temperature.

- Losses were valued at the levelized cost of wind generation. This applies to losses in both radial lines that would serve solely to connect wind generation to the system and to new transmission system elements that would also deliver electricity generated from conventional sources to loads. For new system elements that also deliver electricity generated from conventional sources to loads, the losses due to serving just loads when there is no wind generation are expected to be negligible compared to the losses associated with transmitting the wind generation. A value of $70 / MWh was used as the estimated levelized cost for wind generation.
- A discount rate of 8.09% was used in present value calculations. This is an indicative value for Maritime Electric's weighted average cost of capital, assuming 57.5% debt at a bond rate of 6.5% and 42.5% equity with an expected return of 10.25%. The corresponding present value factor for the expected 40 years life of transmission assets with zero escalation is 11.8.

An analysis involving cost of losses is shown in Appendix 4.

<u>Requirements for Wind Turbine Generators</u>

In developing the transmission system expansion plan, the following assumptions have been made about the capabilities of wind turbine generators.

- The generators will be capable of maintaining 1.0 per unit voltage at the generator terminals while producing full real power output and operating at power factors in the range of +/- 0.98. In other words, as conditions change on the Maritime Electric system, the generators will automatically adjust their reactive power output within the range of +/- 0.98 power factor as necessary to maintain the voltage at the generator terminals at 1.0 per unit.
- The generators will have a low voltage ride through (LVRT) capability that meets the proposed FERC standard.

5. ESTIMATED COSTS FOR TRANSMISSION SYSTEM ELEMENTS

The table below shows current estimated costs for each of the major transmission system elements that were considered for the proposed transmission expansion plan. In addition to materials and labour, these estimates include allowances for easements, engineering and project management, and contingency. The labour costs for transmission line construction are based on the work being done by Maritime Electric line crews or on-Island contract line crews. If off-Island contract line crews need to be brought in, then the labour costs would be considerably higher.

69 kV 477 MCM transmission line, per km	$ 40,000
138 kV 477 MCM transmission line, per km	$ 69,000
138 kV 795 MCM transmission line, per km	$ 122,000
69 kV circuit breaker position, each	$ 250,000
138 kV circuit breaker position, each	$ 300,000
Cost to establish a new 138 kV substation, each	$ 550,000
50 MVA 69 kV / 138 kV autotransformer with OLTC, each	$1,500,000
10 MVAr 138 kV capacitor bank, each	$ 200,000
138 kV circuit switcher position for capacitor bank, each	$ 150,000
138 kV metering installation, each	$ 100,000

The cost for a 138 kV 795 MCM line is much higher than for a 477 MCM line because the size and weight of the 795 MCM conductor necessitates the use of a larger structure to support it. The 477 MCM conductor can be supported with a single pole structure using synthetic insulators (armless construction), whereas it has been assumed that the 795 MCM conductor would require an H-frame structure. As well, the use of an H-frame structure would necessitate a cross-country right of way, which would incur significant easement costs. In comparison, a single pole structure can be placed along a highway right of way.

The selection of the recommended conductor size is discussed in Appendix 3.

6. OWNERSHIP

Maritime Electric will finance and own all transmission infrastructure up to the transmission voltage substations for the wind farms, including the metering equipment at each substation. There are at least four reasons for this approach.

The first reason is that the number, size and location of wind farm substations are best determined by the wind farm developer as part of the overall development of a wind farm. What Maritime Electric might consider as the optimal size for a substation may not be so from the point of view of the wind farm developer. Therefore the wind farm developer should design and own the substations associated with his wind farm.

The second reason is that a renewable portfolio standard (RPS) authorizes the utility to pass on to ratepayers the full cost of the wind generation purchased as part of complying with the RPS. Part of the cost of wind generation is the transmission infrastructure needed to connect the wind farm to the grid, as well as the losses in that transmission infrastructure. If the wind farm developer pays for some of the transmission infrastructure beyond the wind farm, he will just add that cost to the price he charges to the utility for the wind generation.

A third reason is that ownership of the transmission infrastructure by the utility will simplify the administration of a situation where two or more wind farms are connected to the same transmission line, particularly if the development occurs in stages over a number of years.

A fourth reason is that ownership of the transmission infrastructure by the utility will facilitate the use of a postage stamp wheeling charge as part of implementing a transmission wheeling tariff. If wind farm developers were required to contribute to parts of the transmission system, then an adjustment would have to be developed and applied to the wheeling charge for each developer wanting to export wind generation out of PEI.

7. TRANSMISSION EXPANSION PLAN FOR THE WESTERN PART OF PEI

For the purposes of this study, the western part of PEI is taken as being the areas currently served by transmission line T-5, which is more or less everything west of Summerside.

The main potential for wind power development in the western part of PEI is the area to the north and west of Tignish, and down along the western shore as far as West Cape. Stability analysis (Appendix 2) indicates that at 138 kV the practical maximum transfer capability out of this area is about 150 MW. As the installed wind power increases up to a maximum of 150 MW, the associated transmission infrastructure can be installed in stages, as described below.

The description below is based on a scenario wherein there is large scale development at West Cape followed by further development to the north and west of Tignish. However, this should be taken as being indicative. The actual details and sequence of expanding the transmission system will depend on where and when the wind power is installed, but the overall concept (and estimated cost) is expected to end up being much the same.

Phase 1 (up to 50 MW)

The maximum amount of wind power that could be handled by the current 69 kV transmission line running to North Cape from the Alberton substation is about 20 to 25 MW. Voltage control issues and high incremental line losses would make it prohibitive to deliver significantly more than this amount.

Wind power installations in the West Cape area would be served by a new transmission line running west from the O'Leary substation. It would be insulated for 138 kV and initially operated at 69 kV. (Substation transformers for all new wind farms should be equipped with dual 69 kV / 138 kV high voltage windings.)

The conductor size for this new line would be 477 MCM. At O'Leary the line would be terminated with a breaker. With this new line operating at 69 kV, and all of T-5 between Sherbrooke and O'Leary reconductored with 477 MCM, the total installed wind power could be increased to 50 MW.

Phase 2 (up to 100 MW)

Installation of wind power in excess of 50 MW would require the construction of a 138 kV line between O'Leary and Sherbrooke. The recommended conductor size for this line is 477 MCM. The line running from O'Leary to West Cape would be converted to operate at 138 kV. As well, a 50 MVA, 138 kV / 69 kV autotransformer would be installed at O'Leary, as well as 69 kV breakers for the lines going to Alberton and Wellington. With these additions, the total installed wind power could be increased to 100 MW.

Phase 3 (up to 150 MW)

Installation of wind power in excess of 100 MW would require the construction of a 138 kV line with 477 MCM conductor from O'Leary toward Tignish. The line would probably run cross country, generally to the west of Hwy 2, at least as far as to Alberton. North of Alberton the existing 69 kV line could be used by rebuilding it for 138 kV with 477 MCM conductor. The northern termination of this line would probably be north of Tignish near the junction of Hwy 14 and Hwy 161.

At some point there would be a need for a 10 MVAr switchable capacitor bank at 138 kV in the Sherbrooke substation. With these additions, the total installed wind power in the western part of PEI could be increased to 150 MW.

Capital cost

The estimated capital costs for the various stages of the above transmission expansion plan for the western part of PEI are shown in the table below.

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Western PEI	Phase 1	Phase 2	Phase 3	Totals
Installed wind power (MW)	50	100	150	
Trans. infrastructure required:				
- km of 138 kV 477 MCM line	20	56	34	110
- 69 kV breaker positions	1	2		3
- 138 kV breaker positions		3	1	4
- new substations established		1		1
- 138 / 69 kV autotransformers		1		1
- 10 MVAr, 138 kV capacitor bank			1	1
- circuit switcher for capacitor bank			1	1
- 138 kV metering installations	1`		1	2
Estimated capital cost ($ x 1,000)	1,730	7,314	3,096	12,140

Results of load flow analysis

Appendix 1 contains the results of load flow analysis at peak load and at minimum load with 150 MW of wind generation in each of the western and eastern parts of PEI.

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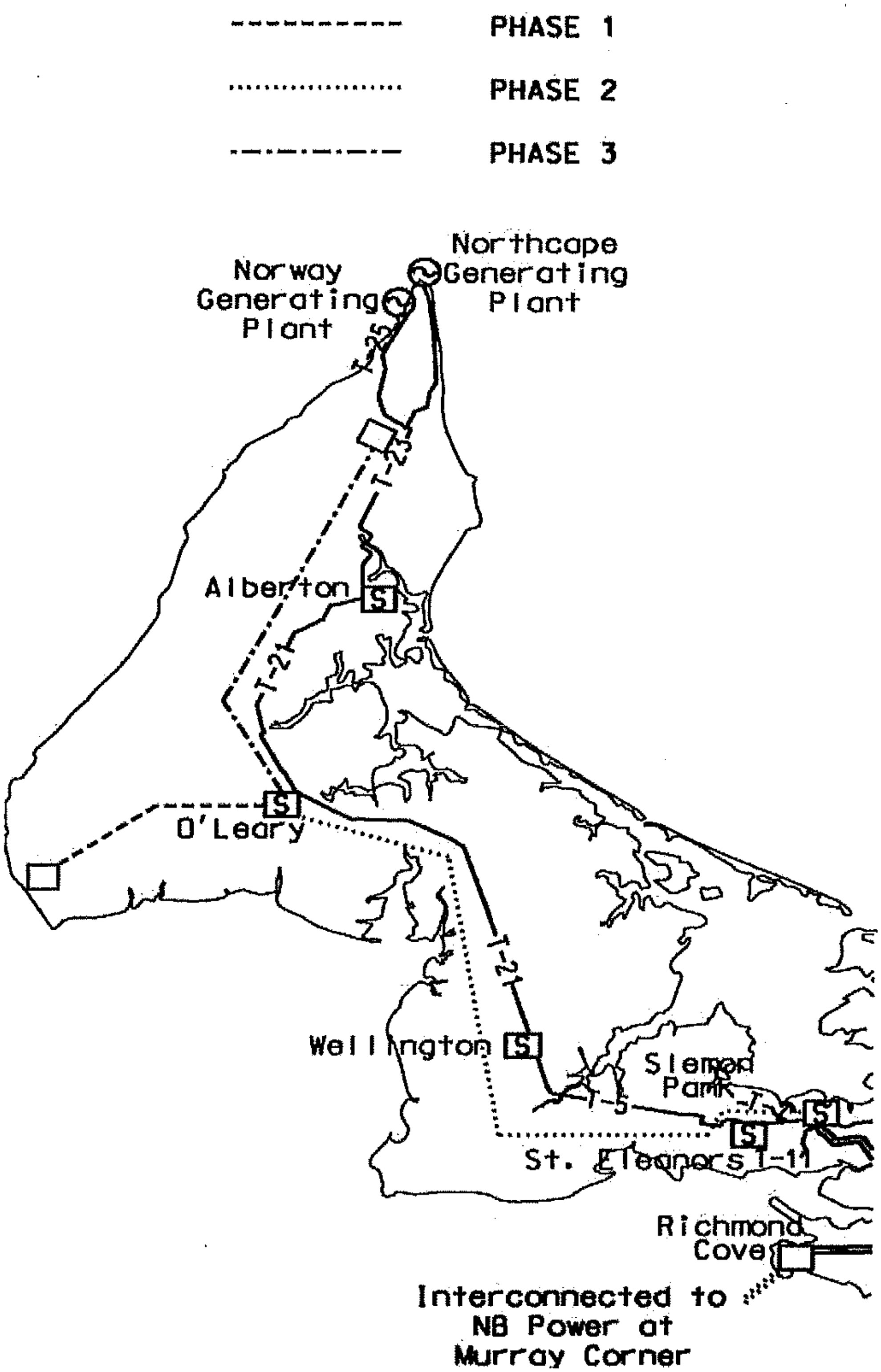
WESTERN P.E.I. EXPANSION PLAN



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8. TRANSMISSION EXPANSION PLAN FOR THE EASTERN PART OF PEI

For the purposes of this study, the eastern part of PEI is taken as being the areas currently served from transmission lines T-2 and T-4, which is more or less everything east of Charlottetown.

The main potential for wind power development in the eastern part of PEI is in the area to the north and east of Souris. Stability analysis (Appendix 2) indicates that at 138 kV the practical maximum transfer capability out of this area is about 150 MW. As the installed wind power increases up to a maximum of 150 MW, the associated transmission infrastructure can be installed in stages, as described below.

<u>Phase 1 (up to 50 MW)</u>

Government's proposed 30 MW wind farm for the East Point area would be served by a 477 MCM line running along secondary roads right-of-ways between Dingwells Mills and a location near East Point. This line would be insulated for 138 kV, but would initially operate at 69 kV. The line would be terminated at the Dingwells Mills substation with a breaker. (Substation transformers for all wind farms connected to this line would be equipped with dual 69 kV / 138 kV high voltage windings.)

With the existing T-8 line between Lorne Valley and Dingwells Mills rebuilt with 477 MCM conductor, and two 69 kV breakers added at Lorne Valley to allow closed loop operation, up to 50 MW of wind power could be installed in the East Point area.

<u>Phase 2 (up to 100 MW)</u>

When the installed wind power exceeds 50 MW, a new 138 kV line with 477 MCM conductor would be built from West Royalty to Dingwells Mills. The line would skirt north of the airport and then follow much of the existing T-4 right-of-way toward Mount Stewart. Scotchfort substation could be tapped off this new line, which would avoid the need to rebuild T-4. Between Mount Stewart and Dingwells Mills the line could run cross country, somewhat south of Hwy 2.

A 50 MVA, 138 / 69 kV autotransformer would be installed at Dingwells Mills, and the previously constructed line to East Point would now be operated at 138 kV. 69 kV breakers would also be added for the lines going to Souris and Lorne Valley. With these additions, the total amount of wind power could be increased to 100 MW.

Phase 3 (up to 150 MW)

When the installed wind power exceeds 100 MW, a 138 kV line between Dingwells Mills and the area to the west of North Lake would be built. At some point there would be a need for a 10 MVAr switchable capacitor bank at 138 kV in the West Royalty substation. With these additions, up to 150 MW of wind power could be installed in the area north and east of Souris.

Capital cost

The estimated capital costs for the various stages of the above transmission expansion plan for the eastern part of PEI are shown in the table below.

Eastern PEI	Phase 1	Phase 2	Phase 3	Totals
Installed wind power (MW)	50	100	150	
Transmission infrastructure required:				
- km of 138 kV 477 MCM line	43	60	30	133
- 69 kV breaker positions	3	2		5
- 138 kV breaker positions		3	1	4
- new substations established		1		1
- 138 / 69 kV autotransformers		1		1
- 10 MVAr, 138 kV capacitor bank			1	1
- circuit switcher for capacitor bank			1	1
- 138 kV metering installations	1		1	2
Estimated capital cost ($ x 1,000)	3,817	7,590	2,820	14,227

Results of load flow analysis

Appendix 1 contains the results of load flow analysis at peak load and at minimum load with 150 MW of wind generation in each of the western and eastern parts of PEI.

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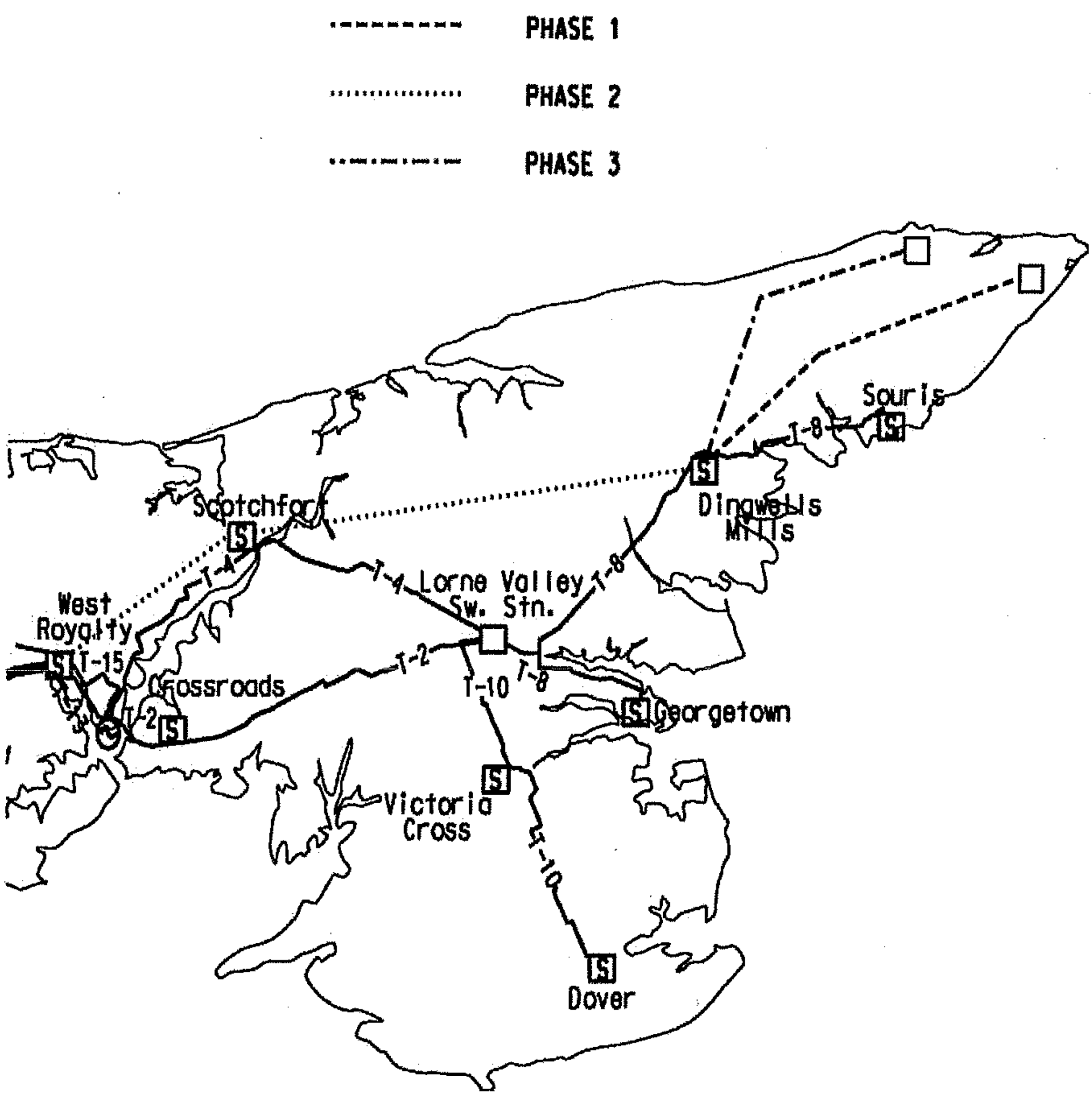
EASTERN P.E.I. EXPANSION PLAN



9. INTERCONNECTION CAPACITY CONSIDERATIONS

The PEI electrical system is connected to the mainland by two submarine cables. Each cable has a nominal rating of 100 MW, which gives a total transfer capacity of 200 MW in either direction. This means that under light load conditions, when the PEI load is approximately 100 MW, up to 300 MW of wind generation on PEI could be accommodated.

However, when the installed wind power begins to exceed 200 MW, consideration will need to be given to what happens under light load conditions if one of the submarine cables is suddenly taken out of service due to a fault. One solution would be to modify the cable overload protection scheme to incorporate rejection of some of the wind generation. However, this could result in some generation being stranded on PEI.

To increase the capacity of the interconnection would involve installing a 200 MW cable inside the utility corridor of the Confederation Bridge. The PEI end of the cable would connect with the PEI power system by means of a short 138 kV transmission line running to Maritime Electric's Borden substation. The New Brunswick end of the cable would be connected to the New Brunswick power system through a new 65 km 138 kV transmission line to NB Power's Memramcook substation. The estimated cost of this project is in the order of $30 million.

If the capacity of the interconnection has not been increased by the time the installed wind power begins to exceed 300 MW, then either a third cable will need to be installed or operating procedures will need to be implemented that limit the amount of wind generation during light load periods so as not to exceed the rating of the interconnection. However, this would result in stranded generation even under normal system conditions.

10. CONCLUSIONS AND RECOMMENDATIONS

It should be a relatively straight forward matter to expand the 138 kV transmission system on PEI to connect up to 350 MW of wind power. The proposed transmission expansion plan can be implemented in stages to roughly match the growth in installed wind power.

The estimated cost to expand the transmission system in the western part of PEI to connect up to 150 MW of wind power is $12.1 million.

The estimated cost to expand the transmission system in the eastern part of PEI to connect up to 150 MW of wind power is $14.2 million.

It is expected that about 50 MW of development could be accommodated in the central part of PEI by connecting to the 69 kV system.

350 MW is suggested as the practical limit on the amount of wind power that can be installed on PEI. If development in excess of 350 MW is desired, then the cost of the associated transmission infrastructure will be proportionally higher, and the use of a voltage higher than 138 kV may be required.

It is essential that wind farm owners be required to operate their wind turbine generators at 1.0 per unit output voltage. This will require that the wind turbine generators be able to supply and absorb reactive power as needed. However this required reactive capability will not be large; a capability of + / - 0.98 power factor operation at full output should be sufficient. The reason is that control of system voltages is improved by having most of the reactive losses in the transmission lines and wind farm substation step-up transformers supplied from the Maritime Electric system.

Synchronous condenser operation or the use of dynamically controlled capacitor banks at high levels of wind generation may be needed to achieve satisfactory control of system voltages.

The proposed transmission expansion plan is expected to result in improved reliability of service for electricity customers in the western and eastern parts of PEI.

APPENDIX 1

Load Flow Results

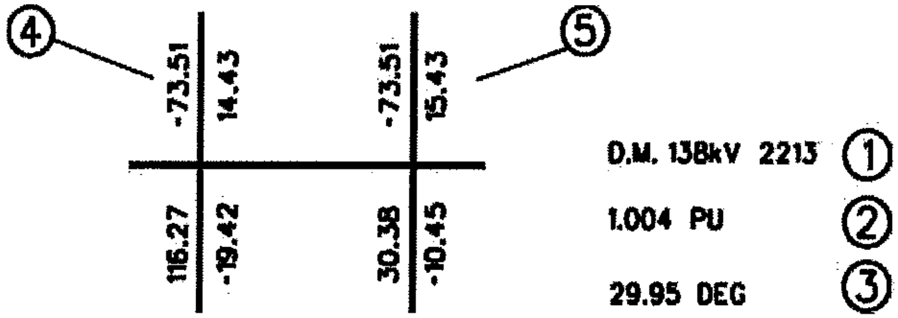
DRAFT

APPENDIX 1

Load flow results

The results of two load flow cases are shown here. One case is for 235 MW of load at the output of the transmission system and 300 MW of wind generation (the peak load case). The other case is for 100 MW of load at the output of the transmission system and 300 MW of wind generation (the minimum load case).

The legend below is intended to help in interpreting the attached load flow results.



1) This identifies the bus as being the 138 kV bus at the Dingwells Mills substation. The number 2213 is the load flow program designation for the bus.

2) The voltage at the bus, in per unit. For example, 1.004 pu means 0.4% above the nominal rated voltage of 138 kV.

3) The voltage phase angle at the bus, in degrees. For example, 29.95 DEG means that the Dingwells Mills bus leads the NB reference bus by 29.95 degrees. The Dingwells Mills bus leading the NB reference bus means that the direction of real power flow is from the Dingwells Mills bus toward the NB reference bus.

4) The real power flow away from the bus on this transmission line, in MW. The negative sign indicates that the flow is into the Dingwells Mills bus.

5) The reactive power flow away from the bus on this transmission line, in MVAr.

APPENDIX 2

System Stability Considerations

APPENDIX 2

System Stability Considerations

Most multi-megawatt scale wind turbines use some form of variable speed operation based on double-fed induction generators or synchronous generators with full power output conditioning.

The double-fed induction generator has a wound rotor with slip rings to allow access to the rotor circuit. Power electronic switching is used to vary the magnitude and phase angle of the rotor current to control reactive power output and to provide for some measure of variable speed operation.

To enable a synchronous generator to operate at variable speed, the full output from the generator is fed through a back-to-back variable frequency power converter. This decouples the power system electrical frequency from the rotor mechanical frequency. In some cases the rotor field is provided by permanent magnets.

For assessing system stability, an advantage of double-fed induction generators and synchronous generators with full power output conditioning is that the reactance of the generator does not need to be taken into consideration. Thus the maximum power transfer is determined by the impedance between the generator terminals and the New Brunswick reference bus.

The starting point for considering system stability is the power-angle relationship. The relationship between the power flowing over a transmission line and the phase angle difference (the "delta") between the voltages at the sending and receiving ends of the line is given by the following formula:

Power = sending end voltage x receiving end voltage x sin (delta) / line impedance

If the sending and receiving end voltages and the impedance are fixed, then the power flow will be a maximum when sin (delta) = 1.0 ; i.e. when the phase angle difference = 90 degrees.

However, operating with delta = 90 degrees would not be practical, because there would be no margin to accommodate system transients. A suggested practical limit is 80% of the theoretical maximum. Since sin 53 degrees = 0.8, at 80% of the theoretical maximum the delta between the sending end and receiving end voltages would be 53 degrees.

From a system stability point of view, the worst case scenario is at minimum PEI load because it has the maximum amount of power being delivered to the New Brunswick system. The load flow analysis shown in Appendix 1 for the scenario of minimum PEI load (100 MW) and 300 MW of wind generation on PEI shows that the phase angle at the terminals of the generators at North Cape and East Point is approximately 41 deg. This is approaching the practical limit of 53 deg (sin 41 deg = 0.66, thus 82 % of the practical limit), and thus additional transmission infrastructure would be required in order to accommodate significant wind power development in excess of 300 MW from these areas.

However, this additional transmission infrastructure would be relatively much more costly. An examination of the load flow diagrams in Appendix 1 shows that if the proposed transmission expansion to accommodate 300 MW of wind power were to be fully implemented, most of the path between East Point and Memramcook would consist of two 138 kV lines in parallel. Similarly for North Cape to Memramcook. This ability to accommodate 300 MW of wind power would have been achieved by adding 138 kV between just East Point to West Royalty and North Cape to Sherbrooke, at a cost of about $26 million.

To provide a significant increase (say 50 %) in transfer capability above 300 MW (to 450 MW) would require the installation of a third parallel line all the way from East Point and North Cape to Memramcook. It would cost about $50 million to do this. Thus the first 300 MW of wind power in the western and eastern parts of PEI could be accommodated with $26 of transmission infrastructure, while the next 150 MW of wind power would require $50 million of transmission infrastructure.

If there were a requirement to accommodate more than 450 MW of wind power on PEI, then the use of a voltage higher than 138 kV should be considered.

For the above reasons, and allowing for the development of 50 MW of wind power in the central part of the Island, 350 MW is suggested as the practical limit on the amount of wind power that can be installed on PEI.

APPENDIX 3

Transmission Line Conductor Selection

APPENDIX 3

Transmission Line Conductor Selection

Selecting the appropriate conductor size for a transmission line involves a trade-off between minimizing the initial capital cost to construct the line and the present value of the cost of losses over the operating life of the line. A larger conductor has a lower resistance to the flow of current, which results in lower line losses because the losses are proportional to the resistance of the conductor. However, a larger conductor means additional capital cost, not only for the conductor itself but also for the poles and structures needed to support the larger conductor.

Over the years Maritime Electric has found it cost effective to standardize on just several conductor sizes. For a 138 kV line the choice for conductor would be either 477 MCM or a larger conductor in the order of 795 MCM.

The thermal ratings and practical ratings for these two conductor sizes are shown in the table below. The practical ratings are indicative of cost effective system design and operation. Except for very short lines, the losses and voltage drops typically start to become excessive when the loading on a transmission line exceeds about one half of its thermal rating. (The thermal rating is the maximum sustained loading at which a transmission line can be operated safely. Thermal ratings are normally only considered for contingency situations.)

	Thermal current rating (Amps)	Practical current rating (Amps)	Practical rating at 138 kV (MW)
477 MCM	670	335	80
795 MCM	900	450	108

Stability analysis (in Appendix 2) indicates that at 138 kV the maximum amount of wind generation that could be practically connected to the system in the eastern part of PEI is about 150 MW. Based on the above table, the obvious way to connect 150 MW of wind generation to the grid at 138 kV would be with two 477 MCM lines. As discussed in Section 8, the tie in point to the grid would be at the Dingwells Mills substation.

Load flow analysis (in Appendix 1) shows that up to one third of the 150 MW would be fed into the 69 kV system at the Dingwells Mills substation tie-in point. New 138 kV transmission infrastructure would be needed to deliver the remaining 100 MW plus to the load center at the West Royalty substation. Based on the above table, the obvious choice appears to be a 138 kV transmission line with 795 MCM conductor.

However, the table in Section 5 shows that the estimated cost for a 138 kV line with 795 MCM conductor is much larger than for a 138 kV line with 477 MCM conductor. An obvious question is would it be more economic to use 477 MCM conductor and incur higher losses than incur the much higher initial capital cost for a line built with 795 MCM conductor. Appendix 4 contains an analysis that shows that the present value of the initial capital cost plus the cost of losses over the life of the line is about the same for the 477 MCM line as for the 795 MCM line with 150 MW of wind generation installed in the eastern part of PEI.

Because of the uncertainty as to how much wind generation will ultimately be installed, and the added difficulty of accessing a cross-country line for maintenance and repairs, the use of 477 MCM for the 138 kV line between Dingwells Mills and West Royalty is recommended.

A second reason for recommending the use of 477 MCM conductor is that Appendix 4 also shows that the total lifetime cost for two 477 MCM lines is approximately the same as for one 795 MCM line when the loading is 110 MW at full output from the wind generation. The second 477 MCM line could be installed when the amount of wind generation reached the level where the savings in losses would justify the cost of the second line. Two lines would also provide improved reliability as compared to the one 795 MCM line.

A similar stability analysis indicates that at 138 kV the maximum amount of wind generation that can be connected in the western part of PEI is also about 150 MW, and similar reasoning leads to the same choices for conductor sizes for the western part of PEI as for the eastern part.

APPENDIX 4

Cost Benefit Analysis

APPENDIX 4

Cost Benefit Analysis

477 MCM versus 795 MCM conductor size

This analysis shows that for a loading of 110 MW at full wind generation output, using a 138 kV line with 795 MCM conductor (which is assumed to require H-frame construction) results in a slightly lower present value cost than a 138 kV line with 477 MCM conductor supported by single pole armless construction.

For Operation at 138 kV	**477 MCM Single Pole**	**795 MCM H-frame**	**Difference**
Initial capital cost ($ / km)	69,000	122,000	- 53,000
Annual losses for 110 MW load (MWh / km)	178	105	
Annual cost of losses at $70 / MWh ($ / km)	12,451	7,369	
Present value of losses over 40 years ($ / km)	146,921	86,953	59,968
Total lifetime cost ($ / km)	215,921	208,953	6,968

As the above table shows, the 795 MCM transmission line is estimated to cost $53,000 / km more to build than the 477 MCM line. However, this additional capital cost is slightly more than offset by the $59,968 / km of increased losses that would be incurred in the 477 MCM line over 40 years.

The conclusion is that using a 795 MCM conductor rather than a 477 MCM conductor would result in a slightly lower total lifetime cost, but the difference is small enough that other considerations could result in the use of 477 MCM conductor being recommended.

One line versus two lines

The above table shows that for a 477 MCM line carrying 110 MW at full wind generation output, the present value of the cost of the losses over the life of the line is $147,000/km. If two lines were used, with each line carrying 55 MW of wind generation at full output, the losses would be reduced by a factor of two. The present value of the cost of the losses would also be reduced by a factor of two to $73,500 / km. Since the estimated cost to install a second 477 MCM single pole line is $69,000 / km, it would be cost effective to install the second line to realize the $73,500 / km savings in losses.

If the amount of wind generation to be carried at full output is reduced to 100 MW, then the present value of the cost of the losses with one line would be $121,400 / km. Adding a second line would result in a savings of $60,700 / km in losses. Since this is less than the estimated cost of $69,000 / km to build the second line, it would be more cost effective to operate with just one line and incur the higher losses.

E

RESPONSES TO QUESTIONS IN A DECEMBER 4, 2017 LETTER FROM DEREK KEY ON BEHALF OF THE CITY OF SUMMERSIDE

Follow up with respect to Question 2:

'a) Further to the Excel workbook that you have provided, it would be helpful if you could provide a similar breakdown with respect to MECL's native load as well as the same for the PEI peak load. The results provided are not consistent with our expectations and therefore this additional information may be helpful to better understand this discrepancy.

Response
We have attached an updated version of the Excel workbook "Coincident peak loads" that corrects errors in the December version. One error was that the transmission losses associated with purchases from New Brunswick by the City of Summerside were double counted. A second error was not showing the firm Point-to Point reservation as being 12 MW starting September 2015.

These errors may be the source of the discrepancy. If not, we will need you to be more precise in terms of what it is you are looking for. (Also, if there still are discrepancies, please identify them.)

'b) I would ask that you provide the FERC calculation using the metric of MECL's load including firm point to point transmission reservations.

Response
In the attached Excel work book entitled "CP FERC tests ", a sheet has been added with the calculations using just MECL's load. No firm point to point transmission reservations have been included because MECL does not have any - MECL uses Network Service. If the intent of the question is that Summerside's firm point to point transmission reservations were to be included in the calculations along with MECL's load, then the results would be slightly more in favour of the use of 12CP because the ratio of winter to summer would decrease slightly.

The results using MECL's load are essentially the same as for the PEI load (previously provided); i.e. the results of the tests are marginally in favour of the use of 12CP.

'c) There appear to be options available with respect to how the FERC calculations are performed and what metrics are used. Please confirm MECL's opinion and rationale for the method of testing used by them.

Response

The attached document "CP tests FERC 20130815123655-ER06-274-007.pdf" (previously sent) is what MECL relied on (starting on page 20). MECL's opinion is that the application of the tests to the PEI situation is straightforward and the Company has no suggestions as to alternate ways of doing the calculations. If the City believes that there are other options, please suggest them.

'**d)** Subject to the results arising from the additional inquiries noted above, is MECL prepared to consider a 3CP method that might better reflect FERC standards?

Response

If Summerside can show that there are other ways of applying the FERC tests, and that the results of those other ways indicate that the use of 12CP is not appropriate, then MECL is prepared to consider the use of 3CP.

Follow up with respect to Question 3

Please confirm if MECL currently incurs a cost with for these scheduling inaccuracies due to wind? If MECL does incur such a cost, please provide the data that supports these costs.

Response

MECL does not incur a cost for scheduling inaccuracies due to wind generation. The reason is that MECL does not own any wind generation. All wind generation for supply of MECL load is purchased from the PEI Energy Corporation, which is the owner of the wind farms. Imbalance charges due to wind generation that are invoiced to MECL are passed on to the PEI Energy Corporation, which pays for them.

Thus, the PEI Energy Corporation, as owner of wind generation, is treated the same as the City of Summerside, as owner of its wind farm, in regard to imbalance charges associated with wind generation.

The following table provides an example of how imbalance charges for PEI are handled.

Wind imbalance charges
17-01-23

IMBALANCE CHARGES EXAMPLE

	Scheduled for the hour (MWh)	Actual for the hour (MWh)	Imbalance for the hour (MWh)	Notes
Maritime Electric load	150	150	0	
Maritime Electric supply sources:				
- wind purchases from PEI Energy Corporation	31	29	-2	(5)
- purchases from NB Energy Marketing	119	121	2	(4)
	150	150	0	
City of Summerside load	15	16	1	
City of Summerside supply sources:				
- generation by Summerside wind farm	6	5	-1	
- purchases from NB Energy Marketing	9	11	2	(4)
	15	16	1	
Suez export from West Cape wind farm	8	9	1	(6)
Loads at Murray Corner (per NBTSO):				
- Maritime Electric receipts	119	121	2	
- City of Summerside receipts	9	11	2	
- Suez receipts (deliveries)	-8	-9	-1	
	120	123	3	(1)
Loads at Murray Corner (per NBEM):				
- Maritime Electric receipts	119	121	2	
- City of Summerside receipts	9	11	2	
- Suez receipts (deliveries)				
	128	132	4	(2) (3)

How the imbalance charges are handled:

1. NBTSO (NB Transmission System Operator) bills NBEM (NB Energy Marketing) for being 3 MWh short.
2. PEI OATT Administrator sends backup to NBEM showing PEI (without export) was 4 MWh short.
3. NBEM sends invoice to PEI OATT Admin for 4 MWh at FHMC (Final Hourly Marginal Clearing Price).
4. PEI OATT Admin sends an invoice to MECL for 2 MWh at FHMC and an invoice to Sside for 2 MWh at FHMC.
5. MECL bills PEI Energy Corporation for 2 MWh at FHMC for 2 MWh shortfall in generation.
6. NBEM sends invoice / payment (equal to NBTSO bill - PEI OATT Admin payment) to Suez.

Follow up with respect to Question 7

I would ask that you provide a copy of the system impact study that was completed prior to the commencement of construction for the Y-104 line. Additionally, if there are additional or supplementary system impact studies for this line, please provide them as well.

Response

Please see the attached 2005 document "138 kV Transmission Expansion Plan for Large Scale Wind Development on Prince Edward Island ".

Line Y-104 was proposed in 2005 as part of the above expansion plan for Maritime Electric's transmission system that would accommodate the development of up to 300 MW of wind power in PEI. The basic idea was to accommodate 150 MW of wind power at each end of the Island by constructing a new 138 kV transmission line out to each of the eastern and western ends of PEI. At the time, the 138 kV system extended only as far west as the Sherbrooke Substation and to the east only as far as the West Royalty Substation.

In nominal terms, a new 138 kV transmission line to the western part of PEI would handle 100 MW of wind power while the existing 69 kV system would handle 50 MW, for a total of 150 MW. Similarly, a new 138 kV transmission line to the eastern part of PEI along with the existing 69 kV system would handle 150 MW of wind power in the eastern part of the Island.

Y-104 is the designation for the 138 kV line to the eastern part of PEI. The first section of new 138 kV line was constructed in 2006 in order to connect the Eastern Kings wind farm to the system. This section of line was initially operated at 69 kV because it was connected to the existing 69 kV system at the Dingwells Mills Substation.

MECL's 2006 Capital Budget Application called for the line to the Eastern Kings wind farm to be constructed for (future) 138 kV operation. To support the request for approval by IRAC of the higher cost for 138 kV construction, the Company included the above identified 2005 expansion plan with the 2006 Capital Budget Application. This 2005 138 kV expansion plan is the planning document for line Y-104.

The last section of 138 kV transmission line construction associated with the eastern PEI portion of the 2005 expansion plan is scheduled for 2017. When complete, the transmission system in eastern PEI will be essentially as proposed in 2005.

Follow up with respect to Question 8

We would note that the two maps that you provided in connection with Question 8 are not one-line diagrams. These appear to be geographical maps. Please provide the one-line diagrams that show the detail connections at the various substations.

Response
Please see the attached.

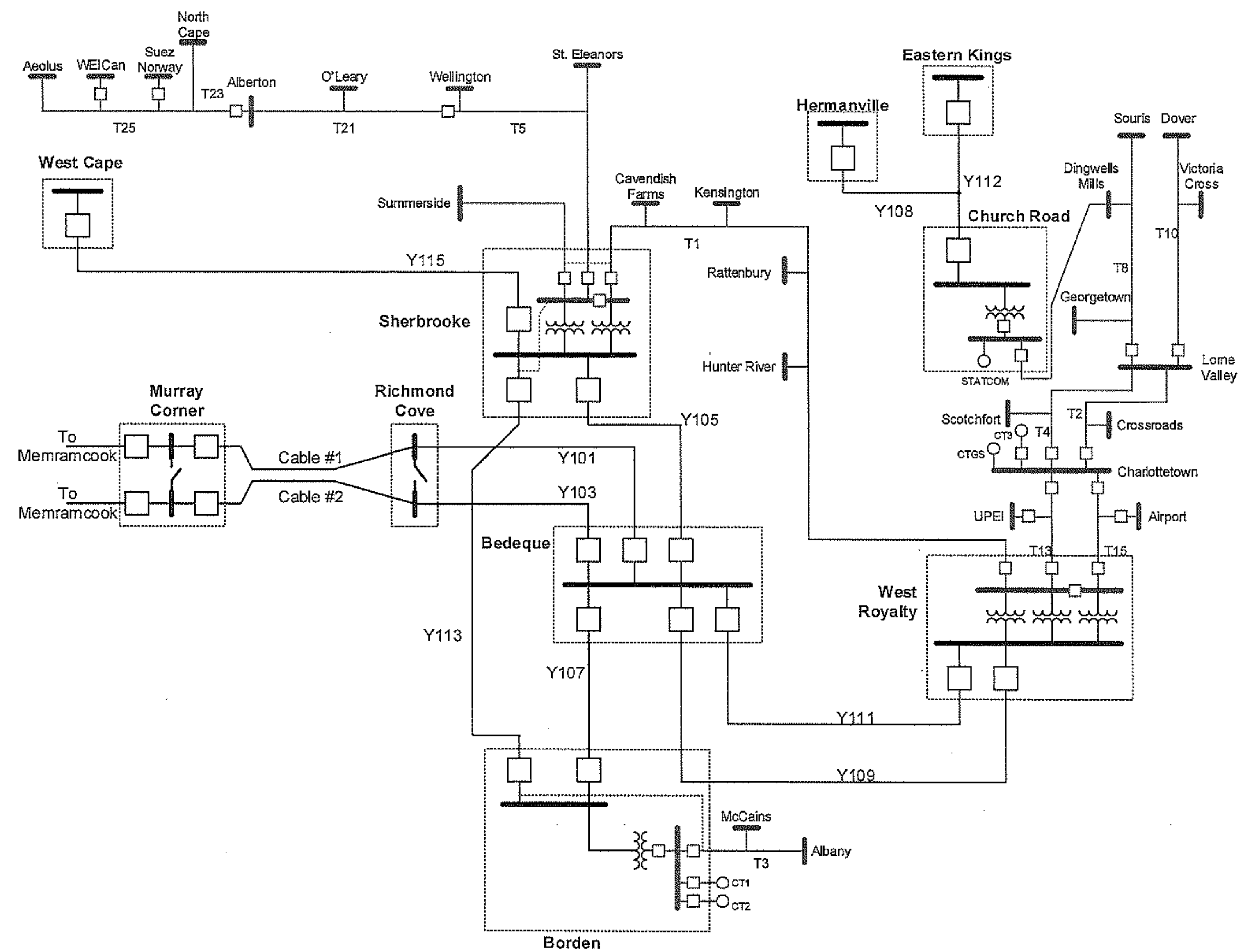
Follow up with respect to the proposed industrial bypass

I would ask that you comment on the rationale used by MECL to include a bypass for only one class of customer as proposed within the current iteration of the OATT.

Response
The MECL OATT is based on the FERC Pro Forma OATT. The section of the FERC Pro Forma OATT that deals with industrial bypass is very specific in that it is for industrial customers only.

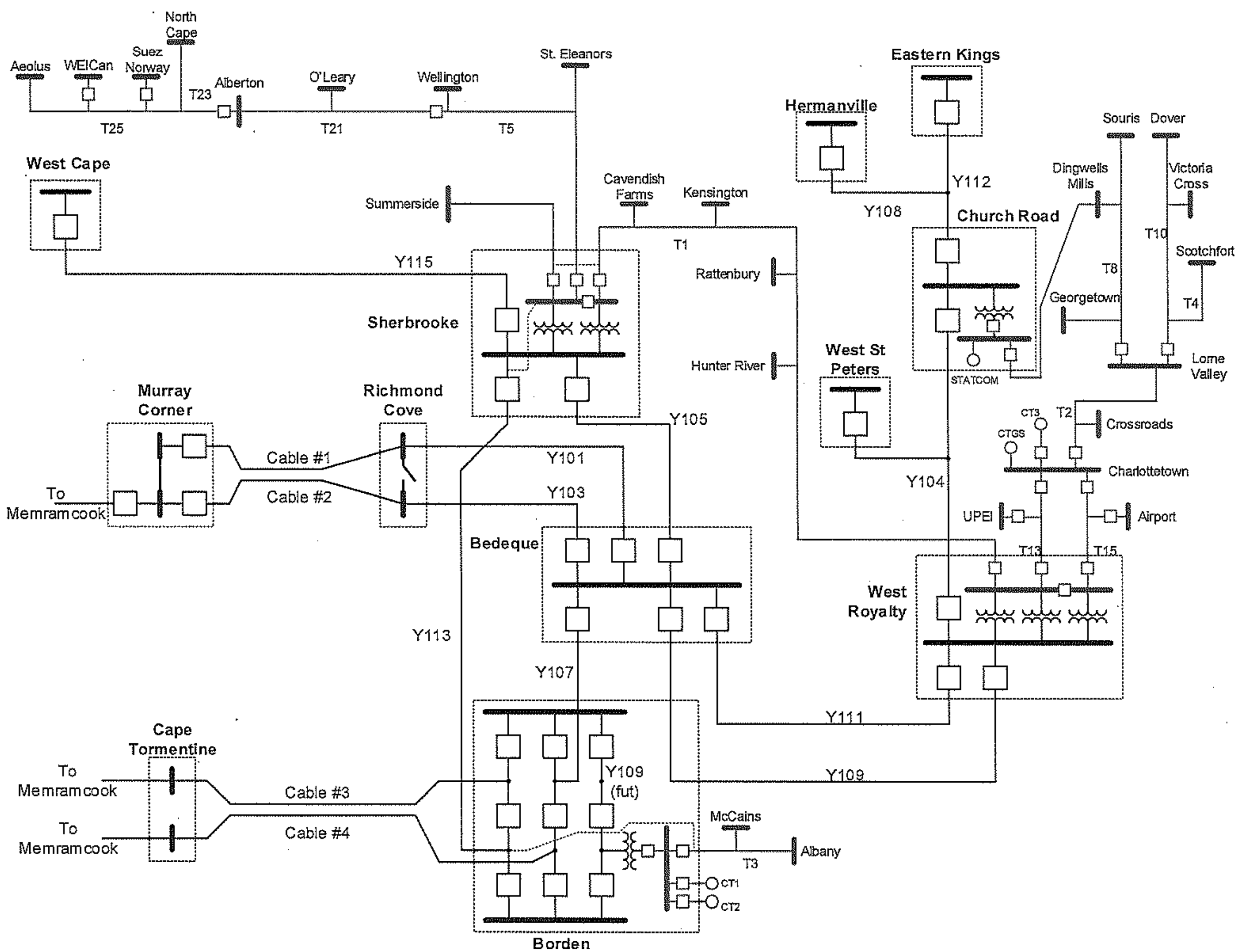
F

System pre-Y104



G

System Post-Y104



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May 10, 2017

Stewart McKelvey
65 Gratfon Street
Charlottetown, PE C1A 8B9

Attention: D. Spencer Campbell, Q.C.

Dear Mr. Campbell:

Re: Maritime Electric Company Limited's ("MECL") Application for an Open Access Transmission Tariff ("OATT")
<u>Our File Reference No. 15042-103dk</u>

Further to the recent direction issued by the Island Regulatory & Appeals Commission in relation to the above noted matter, we are provided the questions set out below in advance of the upcoming deadline for the filing of pre-filed evidence and reports.

The questions that the City of Summerside is posing to MECL are as follows:

1. Please provide an explanation of the differences between MECL's geographical map of the PEI transmission system and the associated one-line diagram that was previously provided (after the Y-104 goes into operation), as there appear to be some differences, including:

   - the one-line diagram does not show the T-7 line to Slemon Park that shows on the geographic diagram between St. Eleanors and Sherbrooke;
   - the one-line diagram does not show the tap and line on the T-1 to New Glasgow that shows on the geographic diagram near Hunter River;
   - the one-line diagram shows the tap on T-1 to Cavendish Farms and the breaker and tap on the T-13 to UPEI which do not show on the geographical diagram; and
   - the one line diagram for Scotchfort appears to show a 69 kV substation at the end of T-4, which is a tap on T-10, whereas the geographic diagram appears to show a 138 kV substation on Y-104.

2. For each of the following assets listed in Schedule "A" as attached hereto, please provide the following pieces of information as at December 31 for each of the years 2013, 2014, 2015 and 2016, together with the forecasts for each of 2017 and 2018:

- Date of installation;
- Original installed cost;
- Gross book value (if different from original installed cost);
- Accumulated amortization; and
- Annual amortization expense.

In the event that all such data are not available for each specific asset, please provide estimates of the values noted based on information that is available, including from:

- Group depreciation accounts for assets accounted for using group depreciation methodologies; and
- Capital expenditure budgets.

Where estimates are provided, please provide supporting calculations.

3. For each of the Taps noted in Schedule "A" as attached hereto, please provide the following information:

- Length of tap in kilometers (or in meters);
- Number of circuits;
- Number of poles (or towers) by type;
- Number of switches by type of switch;
- Number of breakers by type; and
- Installation dates for each of the assets noted above.

We trust that the foregoing is sufficient for you purposes, however, if there are any items that require clarification please do not hesitate to contact me at your convenience.

Yours very truly,

KEY MURRAY LAW

Ryan P. MacDonald
RM/sqj

SCHEDULE "A"

1. Tap on T-21 to O'Leary;
2. Tap on T-5 to Wellington;
3. Tap on T-5 to St. Eleanors;
4. Tap on T-1 to Cavendish Farms;
5. Tap on T-1 to Kensington;
6. Tap on T-1 to Rattenbury;
7. Tap on T-1 to Hunter River;
8. Breaker and tap on T-13 to UPEI;
9. Breaker and tap on T-15 to Airport;
10. Tap on T-2 to Crossroads;
11. Breaker at Lorne Valley feeding the T-10 line and all the facilities off that line all the way to Dover, including the tap on T-10 to T-4 and Scotchfort together with the tap on T-10 to Victoria Cross;
12. Tap on T-8 to Georgetown;
13. Tap on T-8 to Souris;
14. Tap on Y-104 to West St. Peters;
15. Breaker and tap at Sherbrooke feeding the T-11 to Summerside;
16. 138/69 kV transformer and all 69 kV facilities at Borden (providing connections for CT1 & CT2 and the feed to T-3 and McCains and Albany);
17. Facilities at Charlottetown associated with CTGS and CT3;
18. Tap on T-7 to Slemon Park; and
19. Tap on T-1 to New Glasgow.