2021 Regional Transmission Plan Assumptions Update

ERCOT Transmission Planning Assessment

April 6, 2021

Agenda

- DC Tie, Wind, and Solar Dispatch
- Other Reliability Analysis Assumptions
- Economic Analysis Assumptions

DC Tie, Wind, and Solar Dispatch

Craig Wolf

DC Tie Dispatch

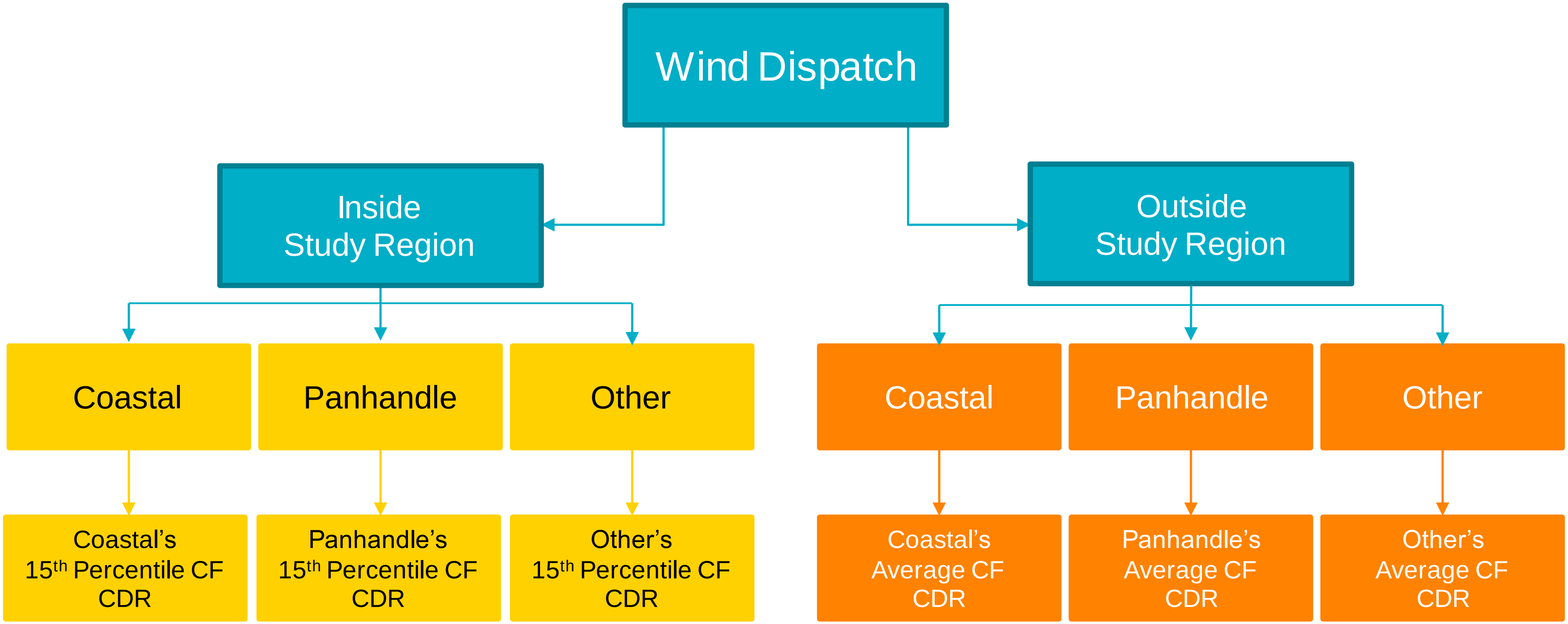
- **Summer Peak Cases:**
  - Analyzed DC tie flows during the top 20 load hours for the past 3 years (60 hours total)
- **Minimum Load Case:**
  - Analyzed DC tie flows during the bottom 20 load hours for the past 3 years (60 hours total)

DC Tie	Summer Peak Case		Minimum Load Case	
	2021 RTP	2020 RTP	2021 RTP	2020 RTP
East	600 MW (IMPORT)	600 MW (IMPORT)	0 MW	0 MW
North	220 MW (IMPORT)	220 MW (IMPORT)	0 MW	220 MW (IMPORT)
Laredo	0 MW	0 MW	0 MW	0 MW
Railroad	0 MW	0 MW	0 MW	0 MW

See Appendix for detailed top and bottom 20 load hours data

Wind Dispatch Methodology: Summer Peak

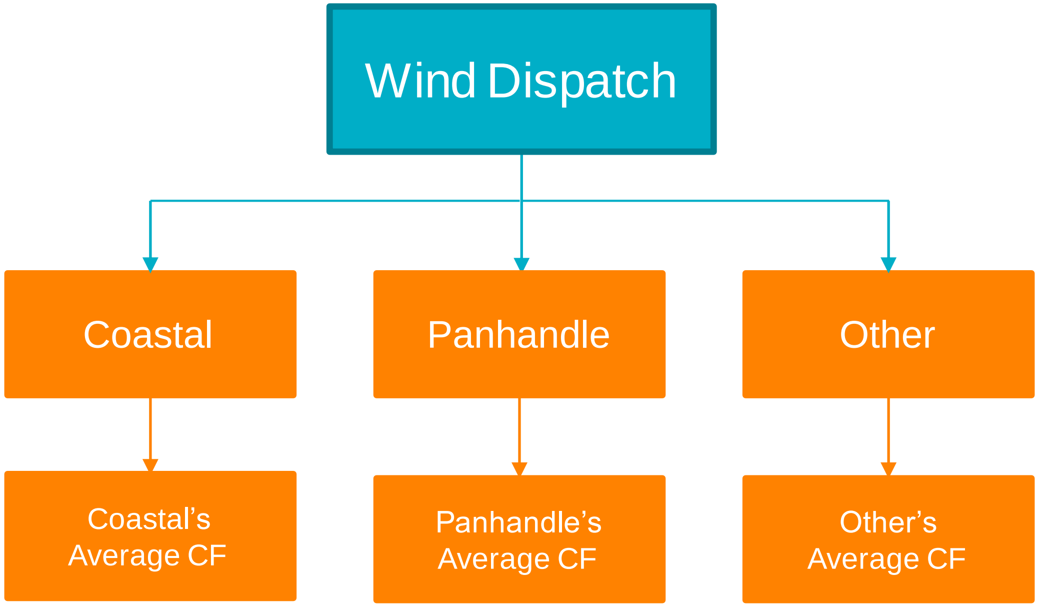
- **Outside Study Region:**
  - CDR weighted average capacity factor for each wind region (Coastal, Panhandle, Other)
  - Based on top 20 load hours of each year
- **Inside Study Region:**
  - CDR weighted 15th percentile[1] capacity factor for each wind region (Coastal, Panhandle, Other)
  - Based on top 20 load hours of each year



1: The 15th percentile capacity factor (CF) is the value at which 15% of the hours have a lower CF and 85% have a higher CF.

Wind Dispatch Methodology: Minimum Load

- **All Wind:**
  - Weighted average capacity factor for each wind region (Coastal, Panhandle, Other)
  - Based on bottom 20 load hours of each year



Wind Dispatch Capacity Factors

Case		2021 RTP Wind Capacity Factors		
		Coastal	Panhandle	Other
Summer Peak	Inside Study Region	40.7%	13.0%	9.6%
	Outside Study Region	60.5%	28.9%	18.7%
Minimum Load	All Study Regions	22.0%	49.1%	36.8%

Solar Dispatch

- **Summer Peak Cases:**
  - CDR weighted average capacity factor for all of ERCOT
  - Based on top 20 load hours of each year
- **Minimum Load Case:**
  - All solar offline

Case	2021 RTP Solar Capacity Factor
Summer Peak	80%
Minimum Load	Offline

Other Reliability Analysis Assumptions

Ping Yan

Battery Energy Storage Modeling Assumptions

- Battery energy storage will be modeled using data provided in response to the following requests for information (RFI) in addition to that available in RIOO

  http://www.ercot.com/services/rq/integration

- For battery energy storage for which RFI responses are not received, an energy to power ratio (E/P) of 2 will be assumed

Battery Energy Storage Dispatch Assumptions

- Transmission-connected battery energy storage will be modeled as online in the reliability analysis
  - Reactive power support will be assumed available
- In the absence of sufficient historical data, the following assumptions will be used for battery energy storage dispatch

Case	Charging?	Discharging?	Subject to Security Constrained Optimal Power Flow (SCOPF)?
Summer peak	No	Up to maximum discharging capability if duration ≥ 4h	Yes
Minimum load	Up to maximum charging capability	No	Yes

Generation Resources Unavailable Prior to NSO

- The following Generation Resources will be taken offline in 2021 RTP based on public announcement (Planning Guide Section 3.1.4.1.1(4))
  - Decker unit 2 will be taken offline in all study years

    Decker Unit 2 Public Announcement
  - Coleto Creek will be taken offline in study year 2027

    Coleto Creek Public Announcement
  - Braunig unit 1,2 and 3 will be taken offline in study year 2026 and 2027, and Sommers unit 1 will be taken offline in study year 2027

    Braunig and Sommers Public Announcement

Study Year	2023	2024	2024 Min	2026	2027
Total Capacity Affected (MW)	420	420	420	1279	2354

Other Assumption Updates

- Multiple generator outages due to a common cause failure will be studied together as a first level contingency in the P3 contingency analysis
- Rooftop solar growth forecast will not be incorporated in 2021 RTP

Economic Analysis Assumptions

John Bernecker

Natural Gas Price Forecasts

- A base forecast and forecasts for high and low natural gas price sensitivities were selected
- The base forecast will be used for the determination of whether or not a proposed project meets the economic planning criteria
- High and low natural gas price sensitivities will be performed for projects with annual production cost savings close to the first-year revenue requirement
  - These sensitivities are intended for informational purposes and will not be used to alter the determination of whether or not a project is considered to have met the economic planning criteria

Natural Gas Price Forecasts

Weather Year Selection

Weather Scenario	Demand Energy	Peak Demand	Winter Peak	Rank Coastal Wind	Panhandle Wind	Other Wind	Solar
2005	10	14	6	15	14	15	11
2006	12	10	14	10	12	7	5
2007	15	13	8	13	15	14	12
2008	11	12	12	3	1	2	2
2009	8	8	11	4	11	8	8
2010	2	3	3	6	9	6	3
2011	1	1	2	1	2	1	1
2012	9	2	13	11	7	4	4
2013	5	5	10	5	10	10	6
2014	6	11	5	2	4	3	9
2015	7	4	9	12	13	13	15
2016	13	9	7	14	3	12	10
2017	14	15	4	8	8	5	7
2018	3	7	1	7	5	11	14
2019	4	6	15	9	6	9	13

*2013 will be used as the base weather year.

Questions

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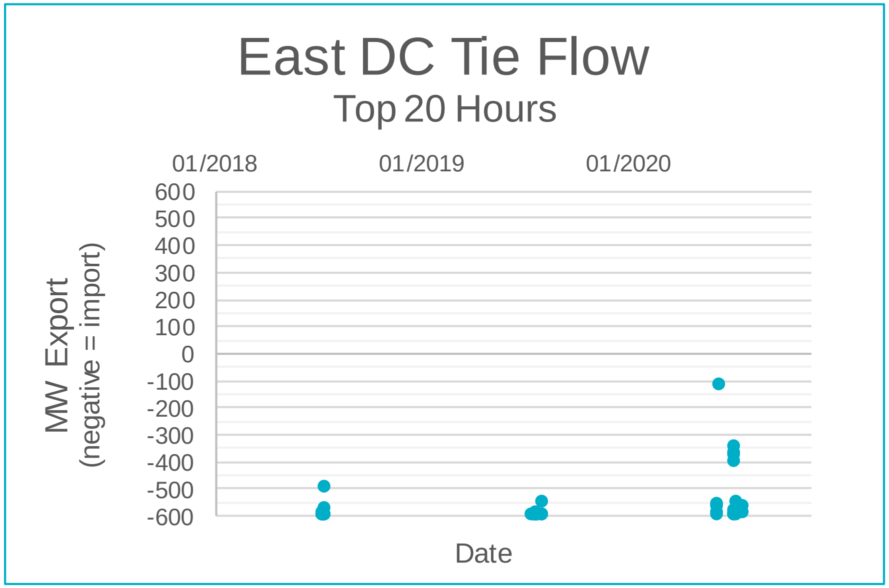
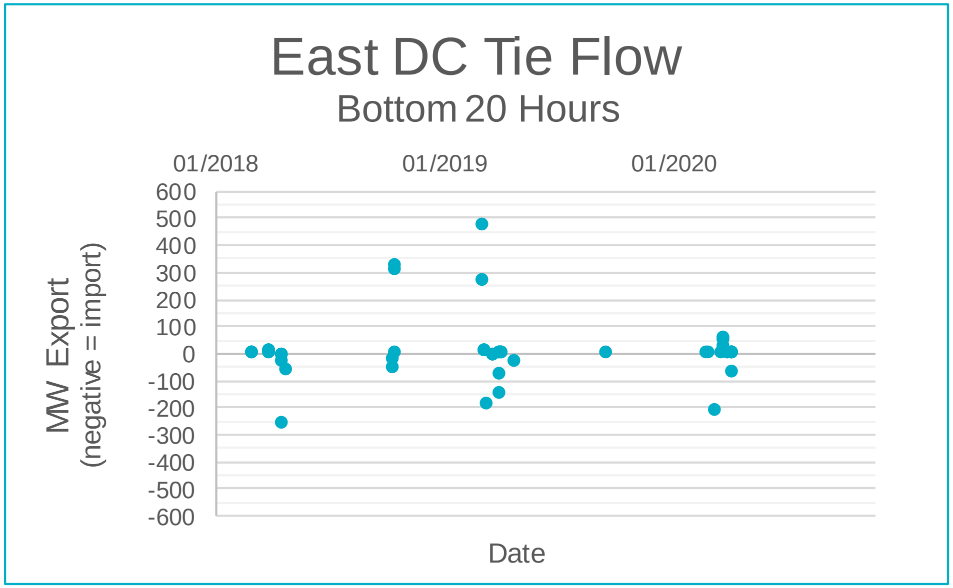
Appendix

2018-2020 Top/Bottom 20 Load Hours - East DC Tie

2018 - 2020 Top 20 Load Hours	
Average Flow	568.4 MW Import
Median Flow	597.4 MW Import
Flow	**% of hours within range**
Import 550 – 600 MW	90%
Import 300 – 550 MW	8%
Import 5 – 300 MW	2%
No Flow	0%
Export 5 – 600 MW	0%

2018 - 2020 Bottom 20 Load Hours	
Average Flow	15.1 MW Export
Median Flow	0.4 MW Export
Flow	**% of hours within range**
Import 100 – 600 MW	7%
Import 5 – 100 MW	23%
No Flow	57%
Export 5 – 100 MW	5%
Export 100 – 600 MW	8%

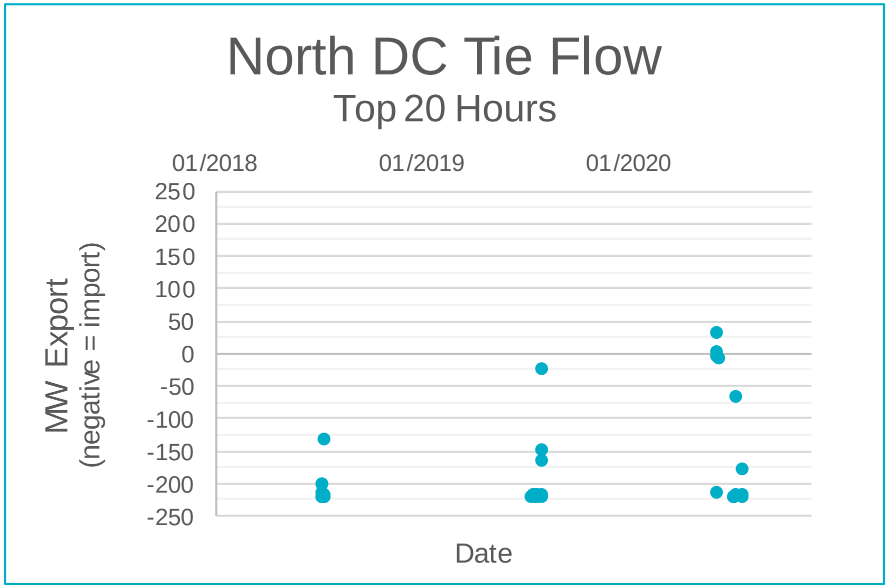


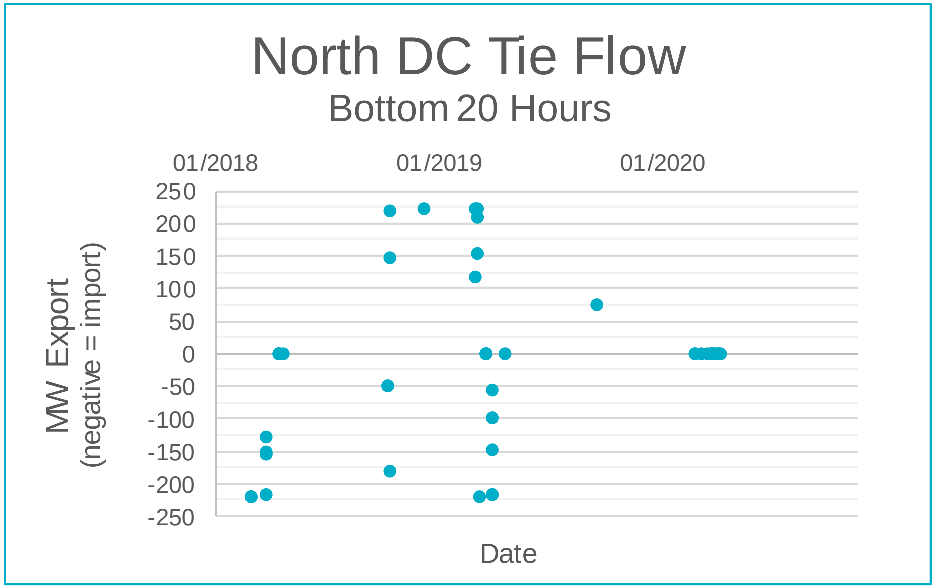


2018-2020 Top/Bottom 20 Load Hours – North DC Tie

2018 - 2020 Top 20 Load Hours	
Average Flow	192.7 MW Import
Median Flow	218.5 MW Import
Flow	**% of hours within range**
Import 200 – 220 MW	80%
Import 100 – 200 MW	10%
Import 5 – 100 MW	5%
No Flow	3%
Export 5 – 220 MW	2%

2018 - 2020 Bottom 20 Load Hours	
Average Flow	27.4 MW Import
Median Flow	0.0 MW
Flow	**% of hours within range**
Import 200 – 220 MW	15%
Import 5 – 200 MW	18%
No Flow	52%
Export 5 – 200 MW	7%
Export 200 – 220 MW	8%

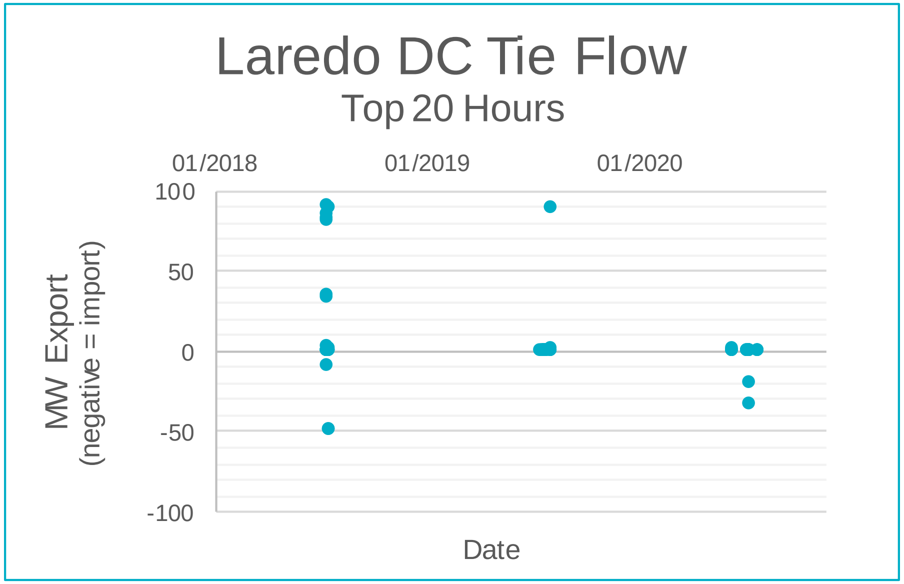


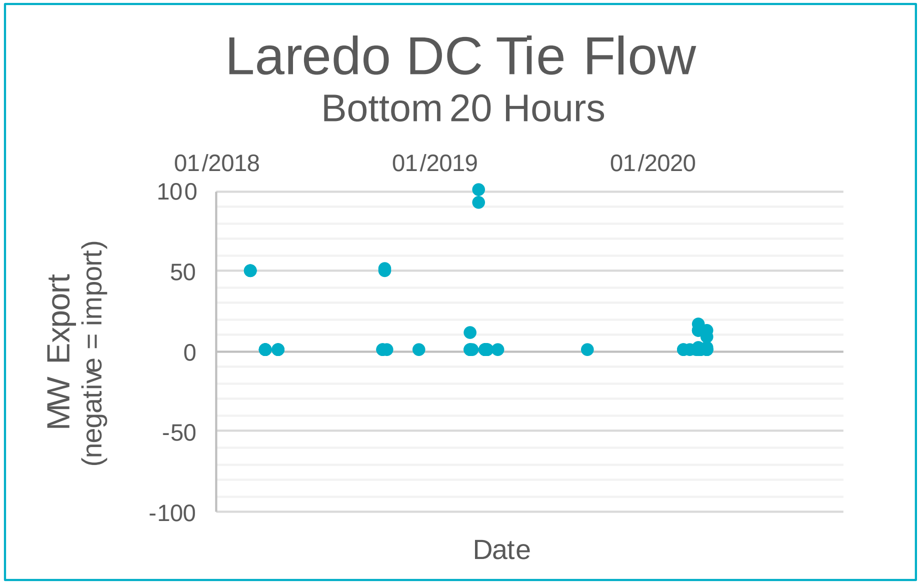


2018-2020 Top/Bottom 20 Load Hours – Laredo DC Tie

2018 - 2020 Top 20 Load Hours	
Average Flow	7.3 MW Export
Median Flow	0.2 MW Export
Flow	**% of hours within range**
Import 50 – 100 MW	0%
Import 5 – 50 MW	8.3%
No Flow	78.3%
Export 5 – 50 MW	3.3%
Export 50 – 100 MW	10%

2018 - 2020 Bottom 20 Load Hours	
Average Flow	18.8 MW Export
Median Flow	0.3 MW Export
Flow	**% of hours within range**
Import 50 – 100 MW	0%
Import 5 – 50 MW	0%
No Flow	67%
Export 5 – 50 MW	18%
Export 50 – 100 MW	15%





2018-2020 Top/Bottom 20 Load Hours – Railroad DC Tie

2018 - 2020 Top 20 Load Hours	
Average Flow	24.5 MW Import
Median Flow	0.4 MW Import
Flow	**% of hours within range**
Import 200 – 300 MW	0%
Import 100 – 200 MW	12%
Import 5 – 100 MW	33%
No Flow	52%
Export 5 – 300 MW	3%

2018 - 2020 Bottom 20 Load Hours	
Average Flow	26.3 MW Export
Median Flow	0.0 MW
Flow	**% of hours within range**
Import 5 – 300 MW	0%
No Flow	73%
Export 5 – 100 MW	15%
Export 100 – 200 MW	10%
Export 200 – 300 MW	2%