CALIFORNIA ISO

California Independent
System Operator

Initial Economic Ranking of Alternatives – Results to Date

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Presentation Overview

- System loss discussion and preliminary results
- Initial economic results for three long-term alternatives
  - Moraga-Potrero
  - Tesla-Potrero
  - Pittsburg-Potrero
- Economic transmission identities

Presentation Caveats

- All results are preliminary and subject to change
- Results to date are based on 2008 simulations
  - Load has not be updated
  - 2011 and 2017 simulations still need to be completed

I. System Loss Discussion and Preliminary Results

System Loss Discussion

- Comparison of modeling techniques (DC OPF vs. AC Load Flow)
- Comparison of peak-hour system losses for:
  - No new line
  - Moraga-Potrero
  - Pittsburg-Potrero
  - Tesla-Potrero
- Comparisons are based on total generation required to cover a fixed system load

Comparison of AC Load Flow and DC OPF Modeling Results

Systems Losses at Peak Hour (1847 MW) as a Function of HVDC Loading

Algorithm	0 MW	200 MW	400 MW
AC Load Flow	838	825	815
DC OPF	729	721	715
Difference	15%	14%	14%

Comparison of Peak Losses for New Transmission Alternatives

Systems Losses at Peak Hour (1847 MW) using AC Load Flow Program

Alternative	System Losses (MW)	Reduction (MW)
No transmission addition	838	0
Moraga-Potrero (AC)	826	-12
Pittsburg-Potrero (DC)	815	-23
Tesla-Potrero (AC)	823	-15

DC line fully loaded, AC lines partially loaded.

II. Initial Economic Results for Long-Term Alternatives

Long-Term Assumptions

- 30-year economic life
- 2011 start date for comparative purposes
- Identical resource plans for 30 years, except for transmission alternative
- No alternative would provide incremental benefits for future transmission expansion
- SF peakers will be built independent of transmission alternative

Assumptions (cont.)

- PG&E Expansion Plan implemented
- CAISO Revised Action Plan for San Francisco implemented
- Hunters Point, Potrero, Contra Costa #6, and Pittsburg #7 retired
- NP15 reserve margin – 15 percent

Peak Load Assumptions

Load Area	2008 (MW)	2011 (MW)	2018 (MW)	Esc. Rate (2008-18)
San Francisco	859	880	916	0.6%
Rest of Peninsula	926	946	980	0.5%
SF & Peninsula	1,785	1,826	1,896	0.5%
NP15	27,119	28,232	30,804	1.3%

Capacity Requirement Assumptions

Parameter	2008	2011	2018
Expected Peak Load (MW)	27,119	28,232	30,804
2008 Resource Capability (MW)	30,116	30,116	30,116
Additional Resource Capability (MW)	1,000	2,400	5,400
Planning Reserve Margin (%)	15%	15%	15%

2011 Assumptions

- Natural gas price -- 7 $/mmbtu (3% esc.)
- 2005-2011 thermal units added include:
  - Consumnes (1000 MW)
  - Metcalf (600 MW)
  - Contra Costa CC (500 MW)
  - Walnut Energy Center (250 MW)
- 2005-2011 thermal units retired – Potrero and Hunters Point, Contra Costa #6, and Pittsburg #7

2017 Assumptions

- Natural gas price – 8.3 $/mmbtu
- 2012-2017 thermal units added include:
  - Tesla CT / CC (1500 MW)
  - Contra Cost CT / CC (1500 MW)
- 2012-2017 thermal units retired – none

Computation of Benefits

- Energy savings -- derived from difference in production costs from a common reference case, includes
  - Energy dispatch savings
  - Loss savings
- Capacity savings

Sources of Energy Dispatch Savings

- Displacement of SF Peakers' generation
  - expands SF / peninsula import capability
  - reduces SF / peninsula congestion)
- Displacement of less-efficient generation

2008 Typical Congestion without New Transmission

- Annual load payment -- $ 6.8 billion
- Annual congestion cost -- $0.4 billion
  - No line congested more than 800 hours per year
  - 80 percent of congestion costs occur off-peak
  - Top 4 congested lines include:
    - Gregg-Hentapi 230
    - Panoche-McMull 230
    - Malin-Round Mt 500
    - McMull-Kearny 230

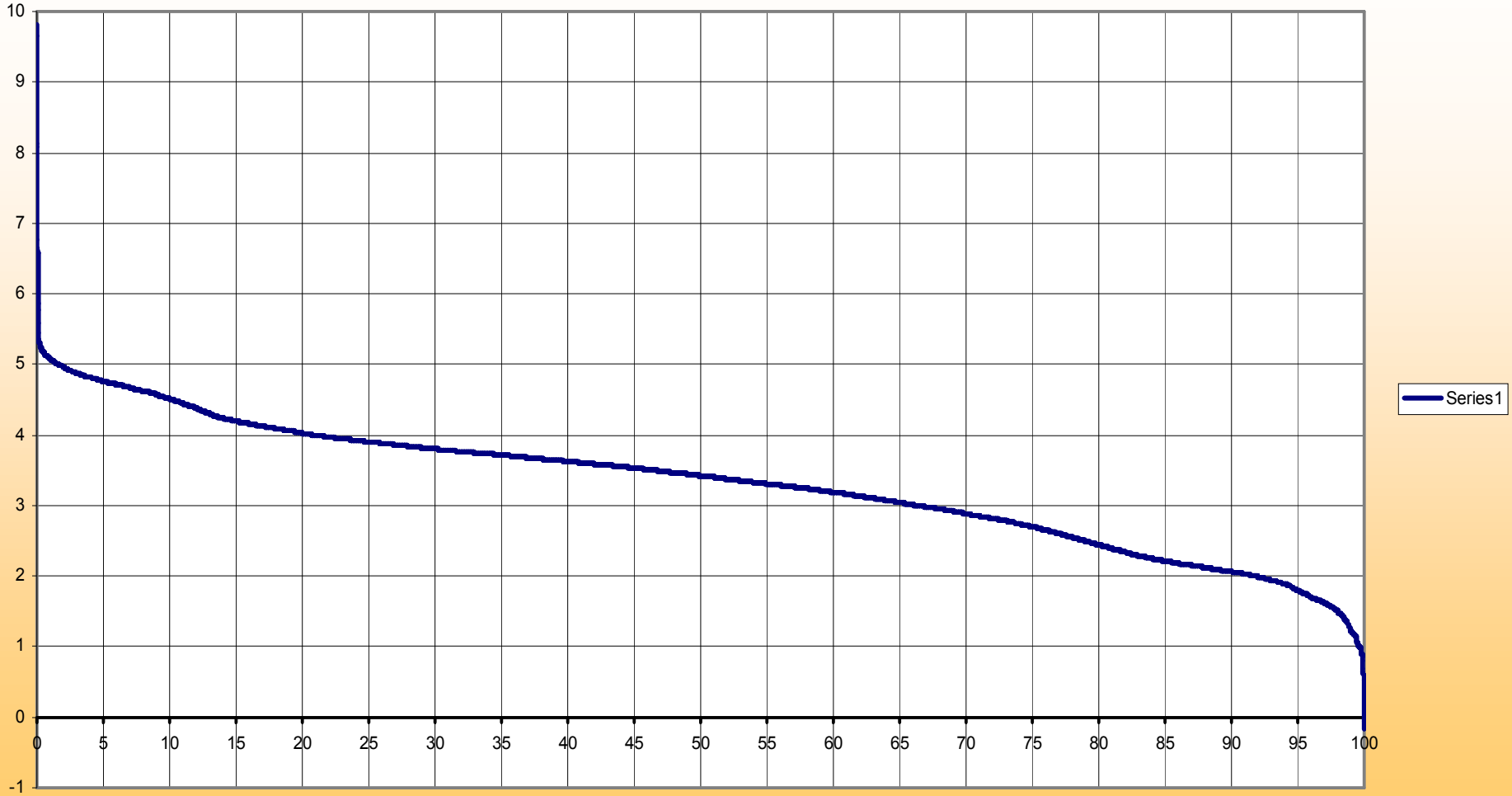
Pittsburg to Potrero – Decre mental Generation

	Station	Before Upgrade (gwh/yr)	After Upgrade (gwh/yr)	Difference (gwh/yr)
1	SF Peakers 1-4	580	547	-33
2	Moss Landing 1-6	8,481	8,472	-9
3	LaPaloma 1-2	5,043	5,037	-6
4	Agnew CT 1	160	157	-3
5	Sunrise Power 2-3	1,561	1,558	-2
6	Morrow Bay 3-4	128	126	-2
	Total for 15 units			-55
	Total for 78 units			-84

Pittsburg to Potrero – Incremental Generation

	Station	Before Upgrade (gwh/yr)	After Upgrade (gwh/yr)	Difference (gwh/yr)
1	LsMdnsS 1-3	5,429	5,440	11
2	Delta CT/ST 1-4	2,192	2,196	5
3	UNCLRsr 1-3	68	74	6
4	Alameda 1-2	91	97	6
5	Shell Oil 3	45	49	4
6	McClure 1-2	417	419	2
	Total for 15 units			34
	Total for 52 units			51

Potrero-Pittsburg Price Differential (LMP)



Capacity Savings

- Expected 2008 peak hour capacity savings
  - Moraga-Potrero (AC) – 12 MW
  - Pittsburg-Potrero (DC) – 23 MW
  - Tesla-Potrero (AC) -- 15 MW
- Value capacity savings at annual CT fixed cost
  - 84 $/kw-yr in 2008 $ (CEC "Comparative Costs . . ")
- Capacity savings in 2008 range from $1 to $2 million per year

Comparison of Annual Energy Losses for New Alternatives

Alternative	System Losses (gwh/yr)
No transmission addition	3,105
Moraga-Potrero (AC)	3,051
Pittsburg-Potrero (DC)	3,072
Tesla-Potrero (AC)	3,105

2008 Preliminary Results

Parameter	Moraga-Potrero (AC)	Pittsburg-Potrero (DC)	Tesa-Potrero (AC)
- prod. cost savings (mil. $)	$2-4	$2-4	$0-1
- capacity savings (mil. $)	1	2	1
- total benefits (mil. $)	$3-5	$4-6	$1-2

2008 Preliminary Observations

- Tesla-Potrero not as economically attractive as other two options
- In 2008, Moraga-Potrero and Pittsburg-Potrero appear to have comparable: (a) energy displacement savings; (b) loss savings; (c') capital costs; and, (d) net costs.
- 2011 and 2017 results may be similar. If so, long-term preferred alternative might be based on: (a) probability of timely completion; (b) risk of cost overruns; and, (c') online date flexibility.

IV. Transmission Identities

Revenue Identity

- The difference in what the consumers pay, and what the generators get paid, is equal to transmission revenue (congestion or wheeling costs)
- CTL – GR = CR
  - CTL – Cost-to-Load (consumer load payment)
  - GR – Generator Revenue
  - CR – Congestion Revenue

Benefit Identity

- The total (or societal) benefits of any capital addition is equal to the difference in production costs, or the increase in the consumer, generator, and consumer surplus (or benefit). (d replaced by delta sign below)
- $TB = \Delta PC = \Delta CS + \Delta GS + \Delta TS$
  - TB – total benefits of a capital addition
  - PC – total production costs for the "without" and "with upgrade" case

Benefit Identity (cont.)

- CS – Consumer Surplus
  - ΔCS = Δ CTL (Cost-to-Load)
- GS – Generator Surplus
  - GS = GR – GC (Generator Cost)
- TS – Transmission Owner Surplus
  - TS = CR (Congestion Revenue)

Example of Benefit Identity

	Area 1		Area 2
	L1 = 2 MWh		L2 = 2 MWh
	G1 = 5 MW		G2 = 5 MW
	= $50/MWh		= $10/MWh
Total Benefits = Dif. in production costs			
	Without Case:		
	T(w/o) = 0 MW		
	PC = (2*$50) + (2*$10)		
	= $120		
	With Case:		
	T(w/o) = 1 MW		
	PC = (1*$50) + (3*$10)		
	= $ 80		
	TB = PC1 - PC2		
	= $120 - $80		
	= $40		

Example (slide 2)

Total Benefits = Sum of difference in consumer, generator, and transmission owner surplus

Without Case:	**With Case:**
P1 = $50/MWh	P1 = $50/MWh
P2 = $10/MWh	P2 = $10/MWh
CTL1 = (2*$50) = $100	CTL1 = (2*$50) = $100
CTL2 = (2*$10) = $20	CTL2 = (2*$10) = $20
CTL = $100 + $20 = $120	CTL = $100 + $20 = $120
G1 = 2 MWh	G1 = 1 MWh
G2 = 2 MWh	G2 = 3 MWh
GR1 = (2*$50) = $100	GR1 = (1*$50) = $50
GR2 = (2*$10) = $20	GR2 = (3*$10) = $30
GC1 = (2*$50) = $100	GC1 = (1*$50) = $50
GC2 = (2*$10) = $20	GC2 = (3*$10) = $30
NP1 = $100 - $100 = $0	NP1 = $50 - $50 = $0
NP2 = $20 - $20 = $0	NP2 = $30 - $30 = $0
NP = $0 + $0 = $0	NP = $0 + $0 = $0

Example (slide 3)

Total Benefits = Sum of difference in consumer, generator, and transmission owner surplus

Without Case:	**With Case:**
P1 = $50/MWh	P1 = $50/MWh
P2 = $10/MWh	P2 = $10/MWh
CTL1 = (2*$50) = $100	CTL1 = (2*$50) = $100
CTL2 = (2*$10) = $20	CTL2 = (2*$10) = $20
CTL = $100 + $20 = $120	CTL = $100 + $20 = $120
G1 = 2 MWh	G1 = 1 MWh
G2 = 2 MWh	G2 = 3 MWh
GR1 = (2*$50) = $100	GR1 = (1*$50) = $50
GR2 = (2*$10) = $20	GR2 = (3*$10) = $30
GC1 = (2*$50) = $100	GC1 = (1*$50) = $50
GC2 = (2*$10) = $20	GC2 = (3*$10) = $30
NP1 = $100 - $100 = $0	NP1 = $50 - $50 = $0
NP2 = $20 - $20 = $0	NP2 = $30 - $30 = $0
NP = $0 + $0 = $0	NP = $0 + $0 = $0

Example (slide 4)

TR = 0		TR = 1*($40) = $40
TB = change in CS, GS, and TS		
CS = $120 - $120 = $0		
GS = $0 - $0 = $0		
TS = $40 - $0 = $40		
TB = $0 + $0 + $40		
= $40		

References

- CAISO Transmission Economic Assessment Methodology (TEAM) Report, Appendix B (17 pages)
  - http://www1.caiso.com/docs/2003/03/18/2003031815303519270.html
- More basic example (8 pages) – CAISO March 16, 2004 TEAM Meeting