

A Proposal for Long-Term Energy Market Design: Interactive Planning Framework (IPF) in Support of Sustainable Technologies

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Based on PhD thesis of Dr. Marija Prica; Thesis Advisor
Professor Marija Ilić; May 2010 Carnegie Mellon University

Outline

- Brief summary and comparison of different centralized planning models
- A proposal for **Long-Term Energy Market Design**: Minimally coordinated IPF for managing systematic and mandatory information exchange between market participants.
- A model and algorithm in support of long-term decentralized decision making by the generators and by the demand and for the interactions with the Long-Term Market Maker (ISO)
- An example

Long – standing planning problems

- Inability to forecast long-term demand accurately
- Inefficiency of long-term planning (capacity under-utilization)
- Multiple performance metrics
- No market mechanism to support new investments
- Lack of systematic signals for new investments
- Non – transparency of long-term bilateral contracts
- Privacy of market participants data

There is a need for transforming the existing planning framework to a more interactive framework in which the necessary data would become transparent and the necessary information would be exchanged.

Our proposal ---Long-Term Energy Market

Interactive planning framework (IPF) for long-term planning

- Interactive framework
 - Preparation phase
 - Negotiation phase
 - Commitment phase
- Transparency of necessary data
- Exchange of necessary information

Key planning considerations

Planning process depends on power industry structure

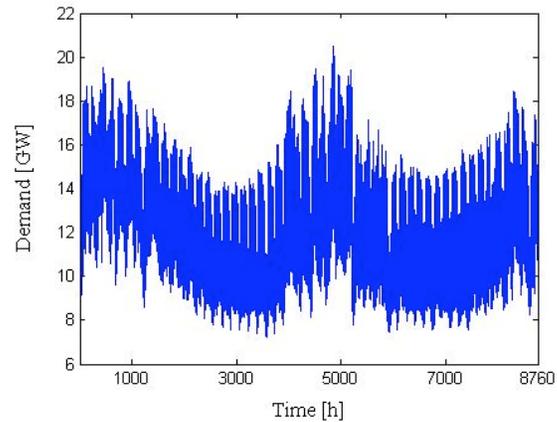
- Traditional
- Restructured

Existing planning models

- Least-cost planning
- Two-part tariff
- Decoupled operations planning
- Centralized peak-load pricing

Demand forecast

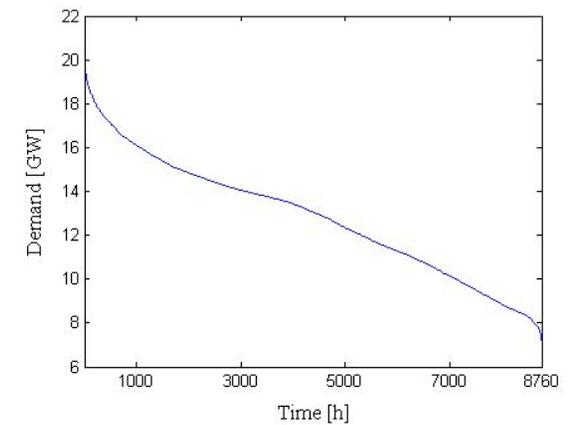
Annual demand



ordering data in descending
order of magnitude

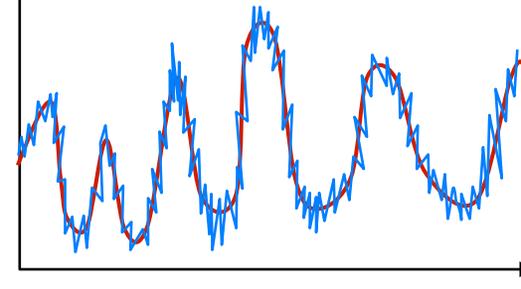


Load duration curve

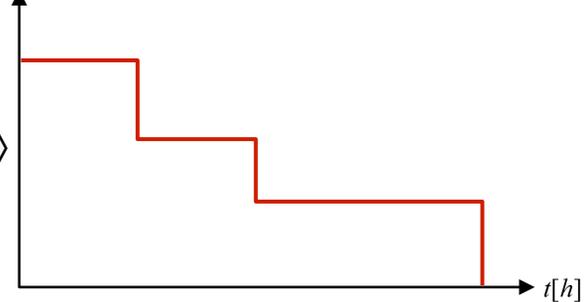


Demand forecast:

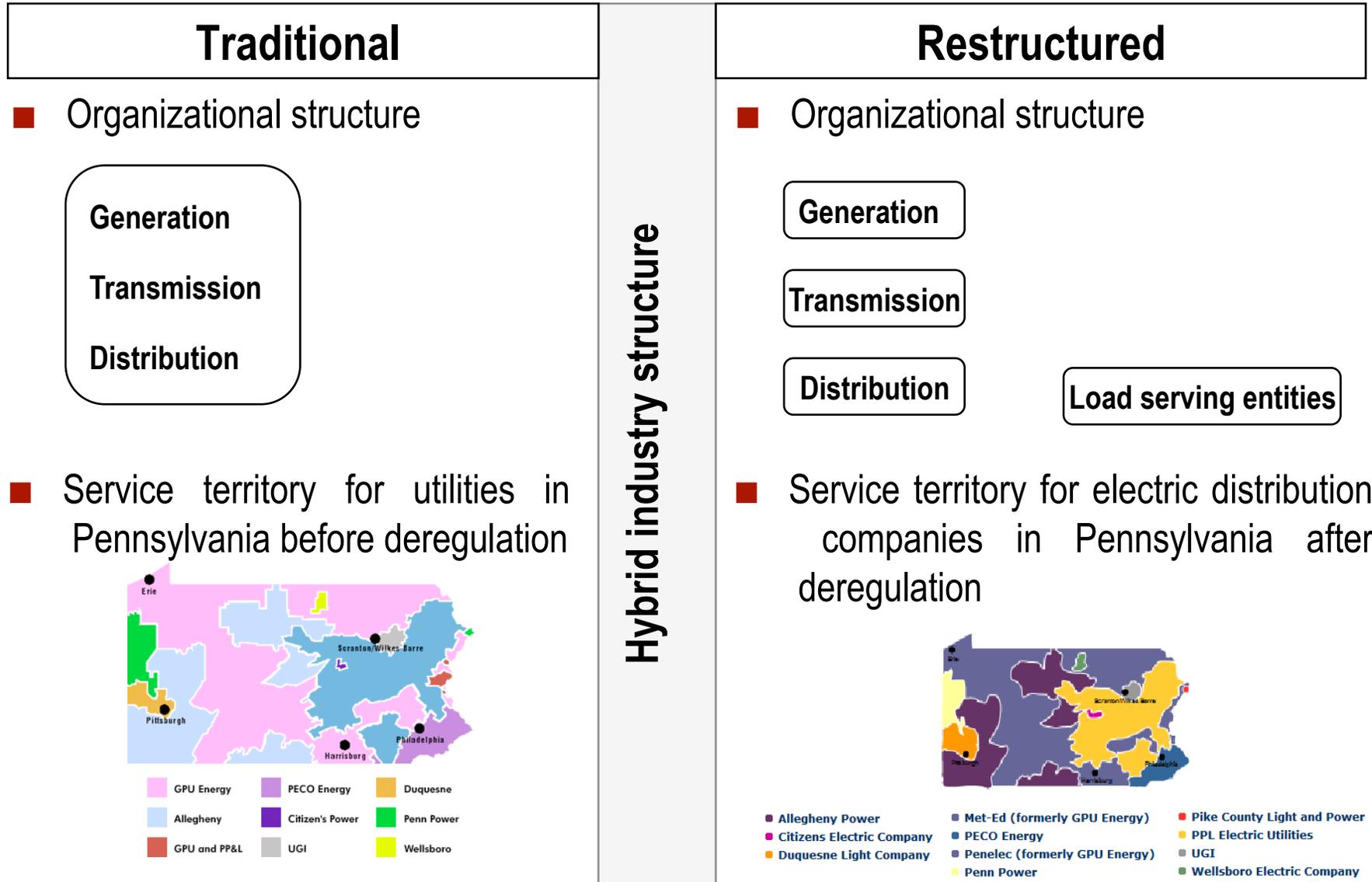
$$P_d(MW) = \hat{P}_d(MW) + \Delta \hat{P}_d(MW)$$



$$L\hat{D}C(MW) = \text{decreasing order of } \hat{P}_d(MW)$$



Power Industry Structures

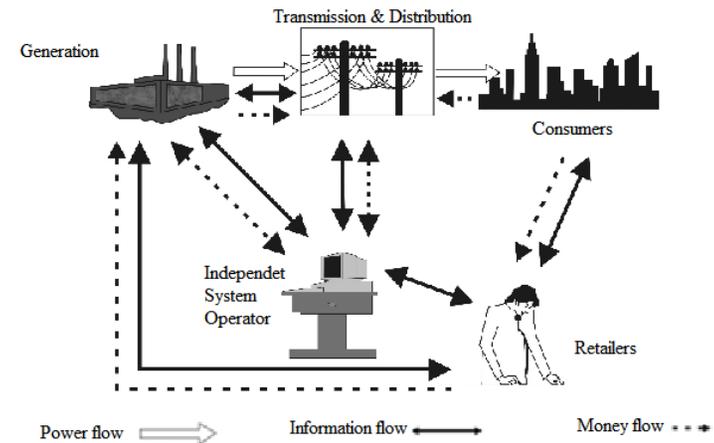
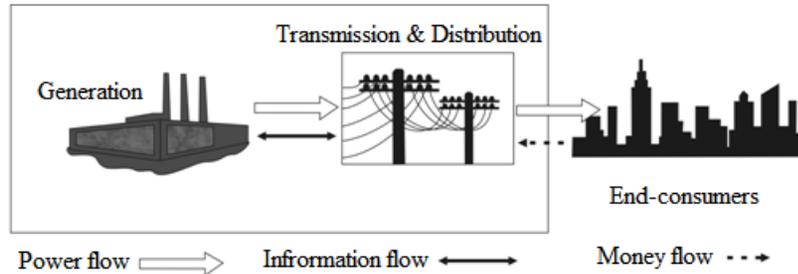


Dependence on Power Industry Structure

Traditional

Restructured

Power, information and money flow



Long-term planning goals

Least- cost planning (utility)

Profit maximization (generators)

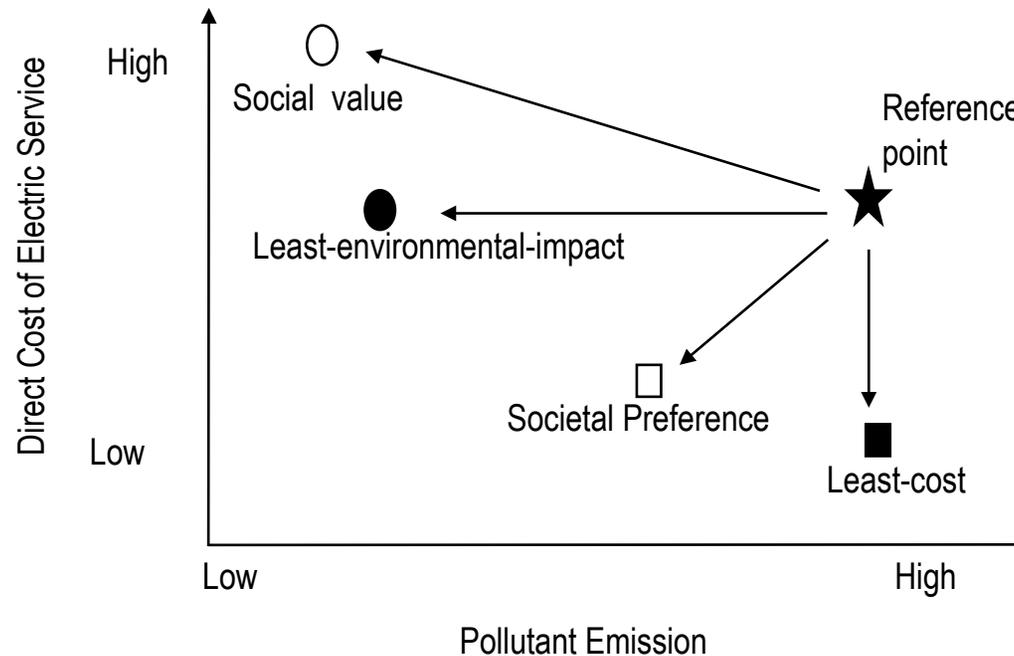
Utility maximization (demand)

Required reliability level (ISO)

| Duquesne Light Company Basic Service Charges | | |
|----------------------------------------------|-------------------|----------------|
| <u>Current Charges</u> | | |
| Customer Charge | | 7.00 |
| Generation | 684 kWh @ 7.1560¢ | 48.95 |
| Transmission | 684 kWh @ 0.6010¢ | 4.11 |
| Distribution | 684 kWh @ 4.2313¢ | 28.94 |
| Pennsylvania Tax Adjustment | | 0.06 |
| Total Current Charges | | 89.06 |
| Total DLC Basic Service Charges | | \$89.06 |

Multi-attribute trade-off analysis

Multi-attribute optimization is a difficult class of planning problems where more than one attribute needs to be optimized and reconciled with other attributes.



Total, average and marginal cost

- Total cost (TC) is defined as the sum of variable (VC) and fixed cost (FC):

$$TC = VC + FC$$

- Average cost (AC) is equal to the total cost divided by the quantity produced

$$AC = TC / Q = VC / Q + FC / Q$$

- Marginal cost is a cost of producing an additional unit of output:

$$MC = \Delta TC / \Delta Q = \Delta VC / \Delta Q + \Delta FC / \Delta Q \text{ or } dTC / dQ = dVC / dQ$$

- Profit (PR) is difference between total revenue (TR) and total cost where revenue is defined as the product of price (p) and the quantity produced (Q) :

$$PR = TR - TC = p \cdot Q - TC$$

Long-term planning models-centralized

- Least-cost planning (LCP)
- Two-part tariff planning (TPT)
- Decoupled operations planning (DOP)
- Centralized peak-load pricing planning (CPLP)

Least-cost planning model

The main metrics: Minimize net present value of total generation costs over the given time horizon

$$\min_{P_g^{T,t}, \Delta P_g^T} \sum_{T=1}^{T_H} \rho^{-T} \left[\sum_{t=1}^{n_t} \left\{ \sum_{g=1}^{n_g} c_g \left(P_g^{T,t} \right) t_{duration}^t \right\} + \sum_{g=1}^{n_g} RoR \cdot C_g \left(\Delta P_g^T \right) \right]$$

Subject to:
$$\sum_{g=1}^{n_g} P_g^{T,t} = P_d^{T,t} + SRR$$

$$\sum_{g=1}^{n_g} P_g^{\max} = P_d^{T,\max} + LRR$$

$$0 \leq P_g^{T,t} \leq P_g^{\max} + \Delta P_g^T$$

COMPLEX DP PROBLEM

Centralized peak-load pricing

The main idea:

Consumers who are using a system during capacity scarcity period are responsible for investment into new capacity.

The **optimal solution** will be reached if investment into new capital investment equals to cumulative operating inefficiency

$$\max_{P_d^{T,t}, P_g^{T,t}, \Delta P_g^T} \sum_{T=1}^{T_H} \rho^{-T} \left[\sum_{t=1}^{n_t} \left\{ U(P_d^{T,t}) - \sum_{g=1}^{n_g} c_g(P_g^{T,t}) \right\} \cdot t_{duration} - \sum_{g=1}^{n_g} C_g(\Delta P_g^T) \right]$$

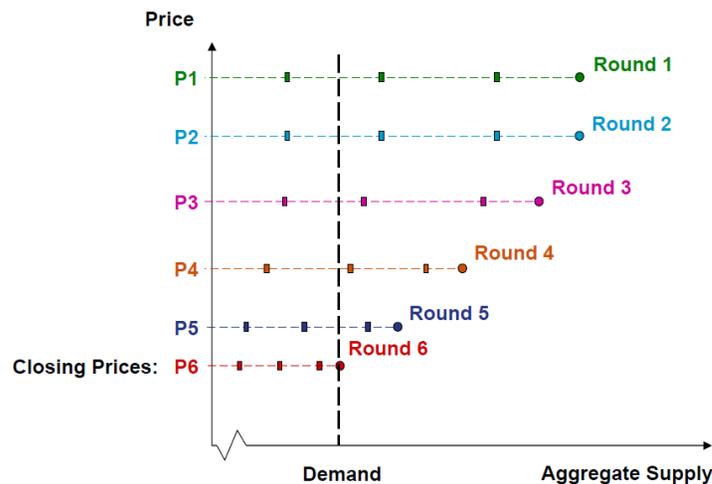
Subject to:
$$\sum_{g=1}^{n_g} P_g^{T,t} = P_d^{T,t}$$

$$0 \leq P_g^{T,t} \leq P_g^{\max} + \Delta P_g^T$$

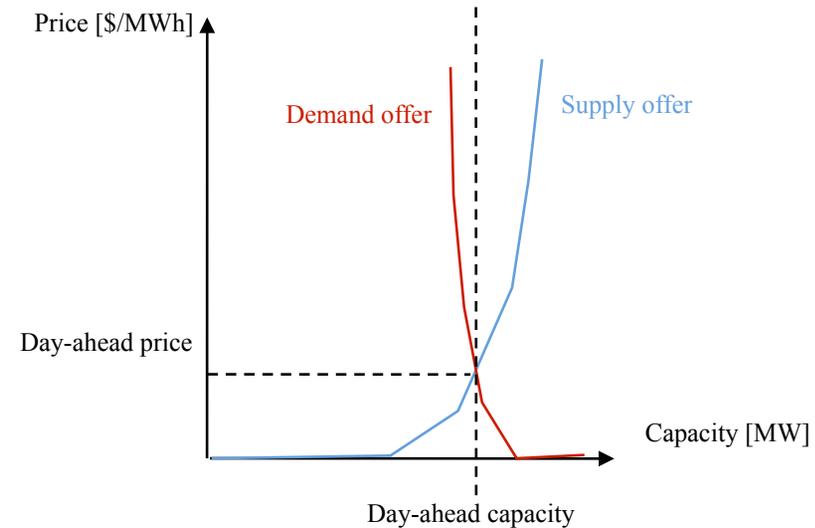
Decoupled operations and planning

The main idea:

To encourage new generation investments by providing more stable revenue to generator owners and to reflect the long-run cost of capacity resources.

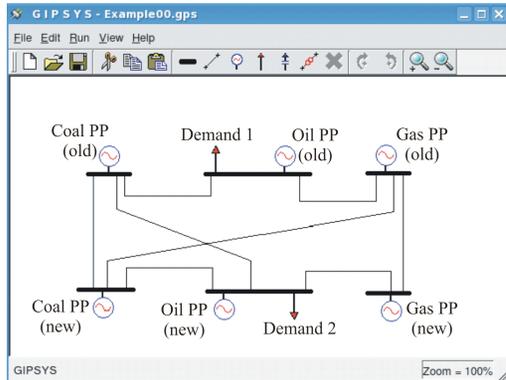


Forward capacity market

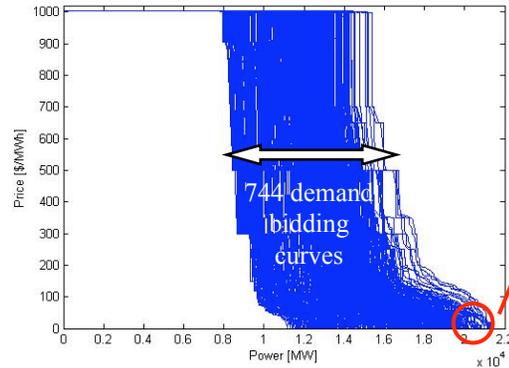


Day-ahead energy market

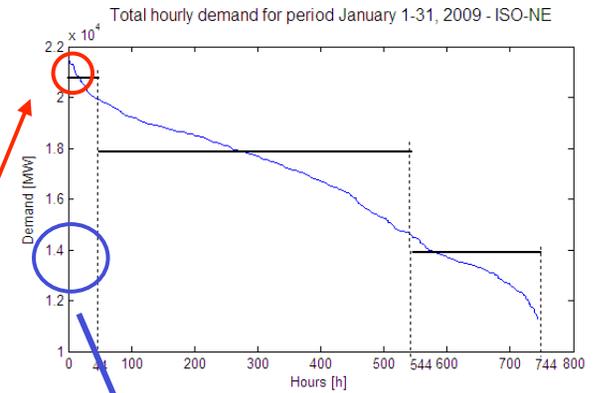
Model comparison – example setting



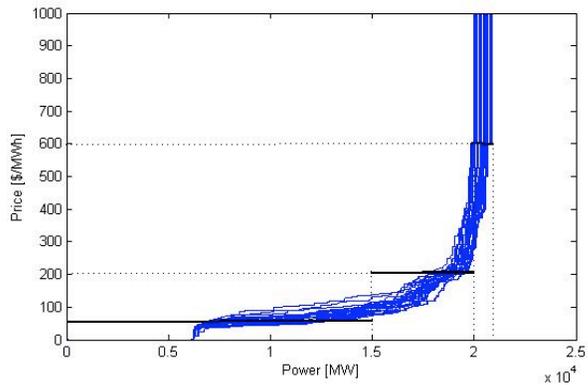
Test system



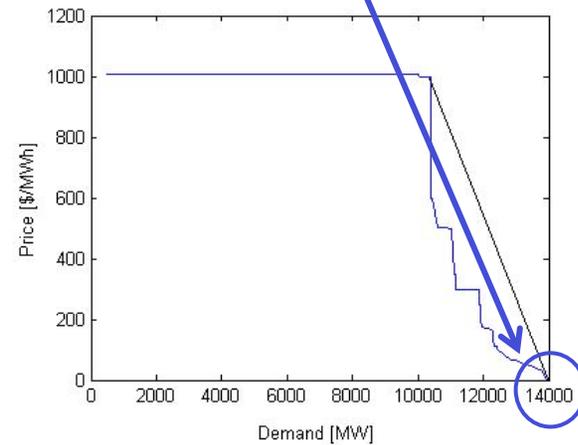
Hourly demand bidding curves



LDC for January 1-31, 2009



Supply Curves for January 1-31, 2009 (ISO-NE)



Demand Bidding Curve – Low

Model comparison – results

| | Demand payment | Total O&M and capital costs | | | Total generation revenue | | |
|------------------------------------------------------|----------------|-----------------------------|--------------|--------------|--------------------------|----------------|--------------|
| | | Base | Intermediate | Peak | Base | Intermediate | Peak |
| [billion \$] | | | | | | | |
| Least cost planning | 19.478 | 19.44 | | | 0.038 | | |
| Two-part tariff (regulated) | 19.478 | 19.44 | | | 0.038 | | |
| Two-part tariff (pay as bid price) | 19.459 | 12.41 | 6.878 | 0.235 | 0.019 | - 0.083 | 0.000 |
| Two-part tariff (uniform price) | 50.890 | 12.41 | 6.878 | 0.235 | 30.46 | 0.904 | 0.000 |
| Decoupled operations planning (uniform price) | 58.717 | 11.449 | 9.068 | 1.154 | 36.265 | 2.151 | 0.145 |
| Peak-load pricing | 43.761 | 12.368 | 4.038 | 0.000 | 27.250 | 0.105 | 0.000 |

Systematic comparison of different planning models.

Key conclusions

- The long run performance (LRP) of all generators is always higher in the LCP than in the CPLP.
- The LRP of all generators is always higher in the DOP than in the LCP.
- For the case of CPLP, the annual capital cost of each generator is always recovered, and equals to the cumulative sum of the short-run marginal profit by the generator over the year.
- Therefore in the case of CPLP (assuming no lumpiness of investment) there is no need for so-called second best tariff in order to implement guaranteed cost-plus capital cost recovery by the generators.
- On the other hand, the LCP and DOP methods require second-best design of payments by the consumers to guarantee cost-plus recovery of capital generation cost.

Key conclusions

- A possible implementation of full “cost +” recovery is so-called two-part tariff, which basically requires that the variable cost be paid according to the short-term ED and the annual capacity cost be recovered through the second part of the tariff.
- CPLP method is the only method which leads to the “optimal” generation mix. The “optimal” generation mix means that the new incremental capital cost investment around such mix is the same as the cumulative inefficiency if such investment is not made.

Single – vs. multi-objective model

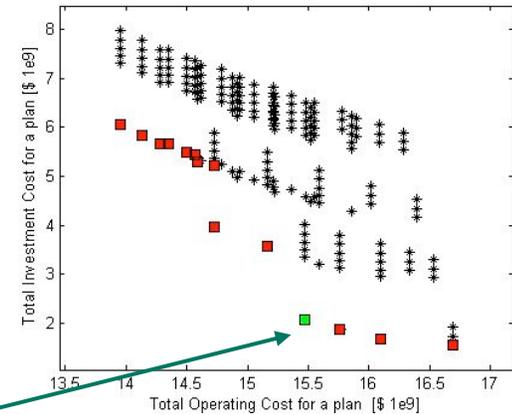
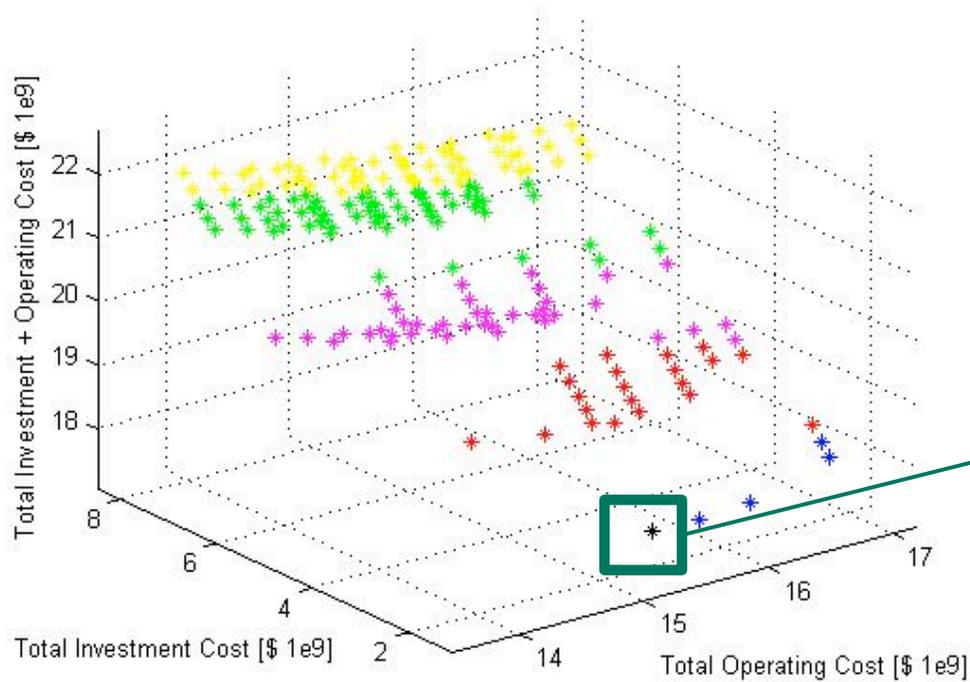
■ Single-objective

$$\min_{P_g^{T,t}, S_g^T} \left(\underbrace{\sum_{T=1}^{T_H} \rho^{t-1} \sum_{t=1}^{n_t} \left\{ \sum_{g \in \text{existing G}} c_g(P_g^{T,t}) \cdot t_{duration}^t \right\}}_{f_1 - \text{Operating Cost}} + \underbrace{\sum_{t=1}^T \rho^{t-1} \sum_{g \in \text{new G}} RoR \cdot s_g^T C_g(P_g^{\max})}_{f_2 - \text{Investment Cost}} \right)$$

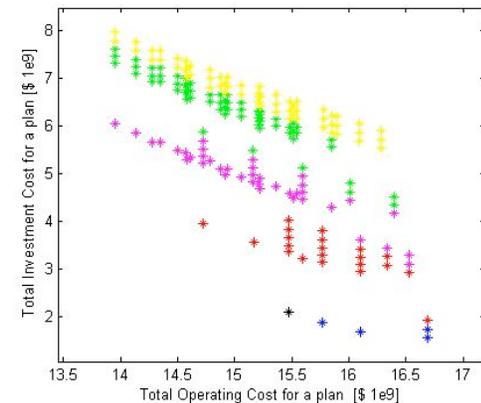
■ Multi-objective

$$\min_{P_g^{T,t}, S_g^T} \left(\underbrace{\sum_{T=1}^{T_H} \rho^{t-1} \sum_{t=1}^{n_t} \left\{ \sum_{g \in \text{existing G}} c_g(P_g^{T,t}) \cdot t_{duration}^t \right\}}_{f_1 - \text{Operating Cost}}; \underbrace{\sum_{t=1}^T \rho^{t-1} \sum_{g \in \text{new G}} RoR \cdot s_g^T C_g(P_g^{\max})}_{f_2 - \text{Investment Cost}} \right)$$

Single – vs. multi-objective model comparison



Pareto frontier

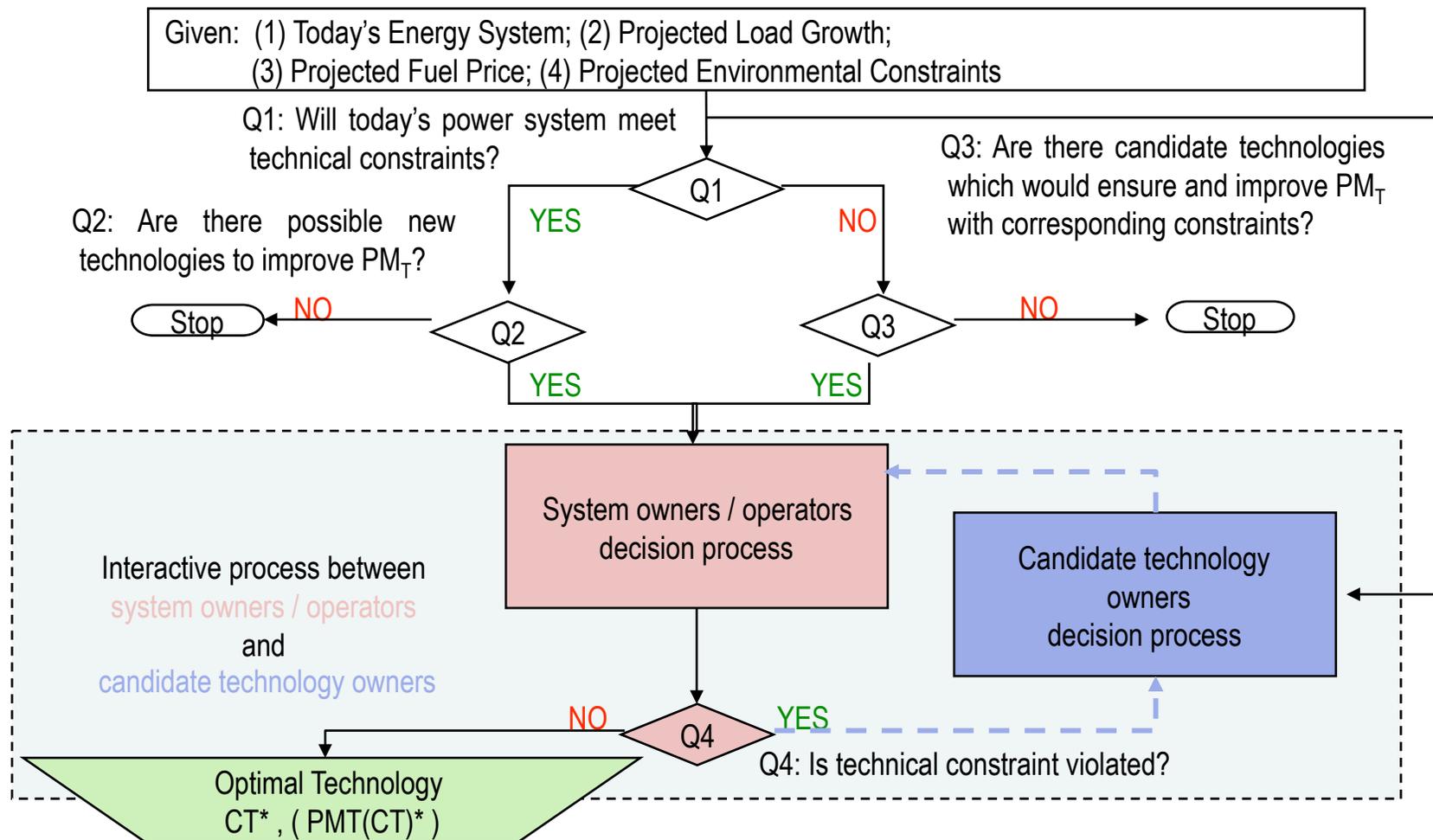


Multi-attribute planning

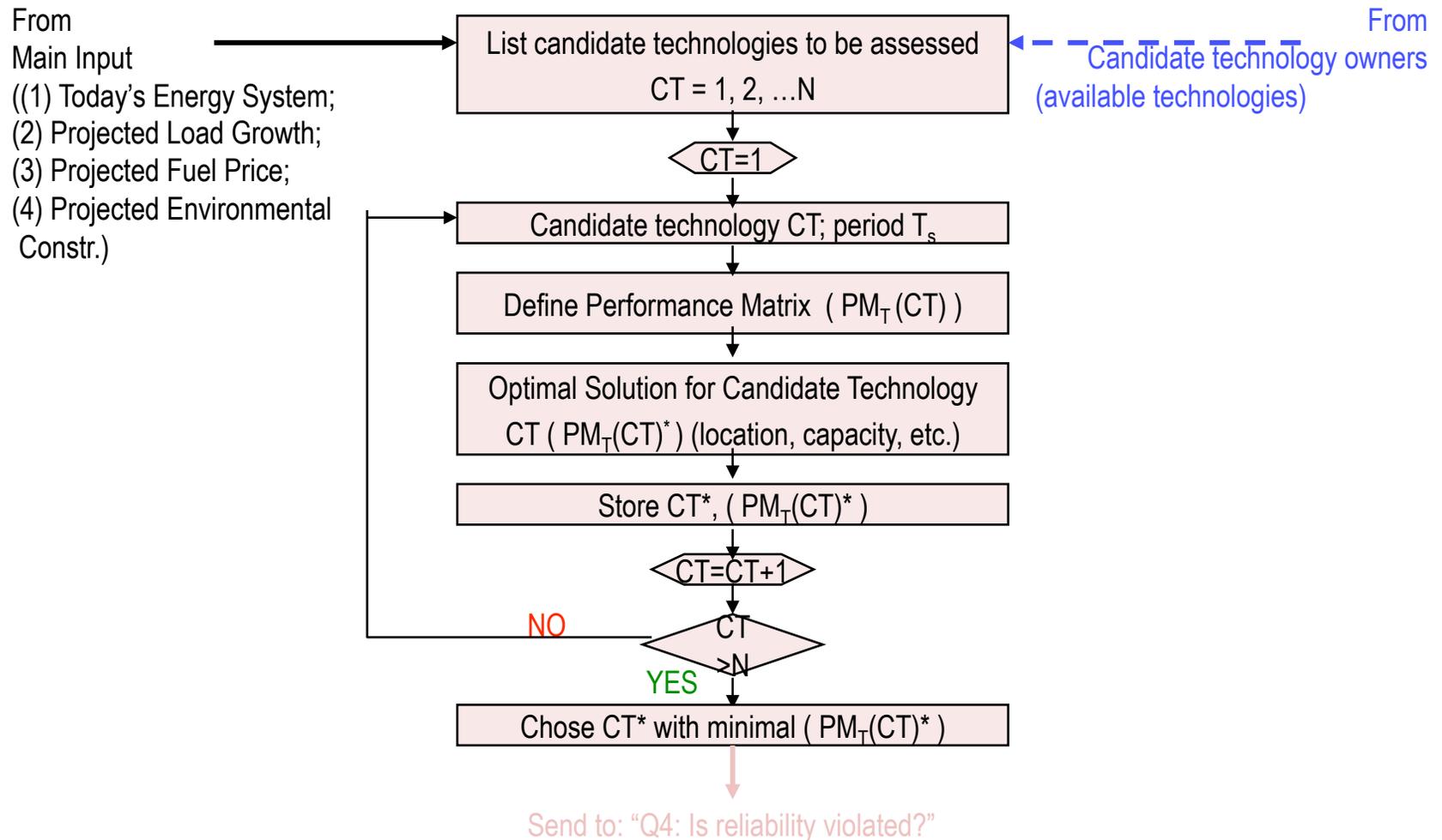
Single-attribute vs. multi-attribute planning

The given example illustrates that multi-objective optimization problem gives the planner an option to select the best possible plan based on the trade-off between different objectives.

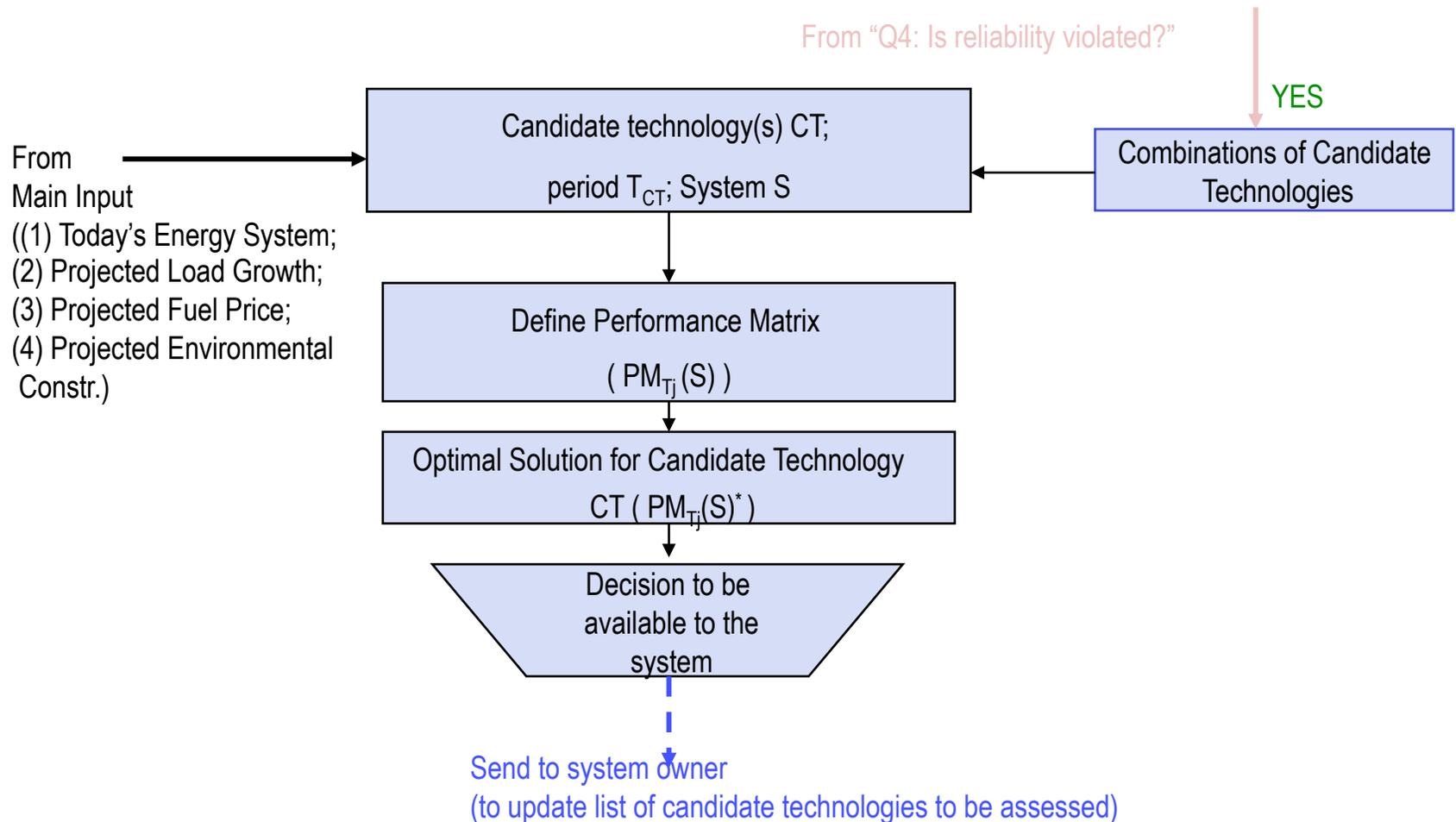
Interactive planning framework (IPF)



System Owners / Operators Decision Process



Candidate Technology Owner Decision Process

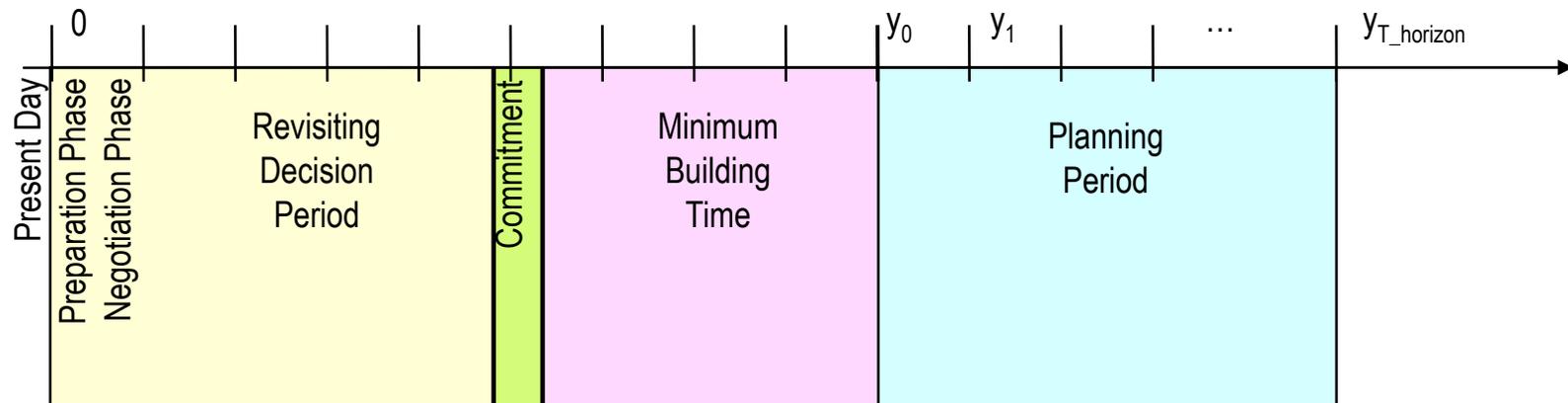


Basic Market design—

Phases and different phases time line

Interactive planning framework consists of three phases:

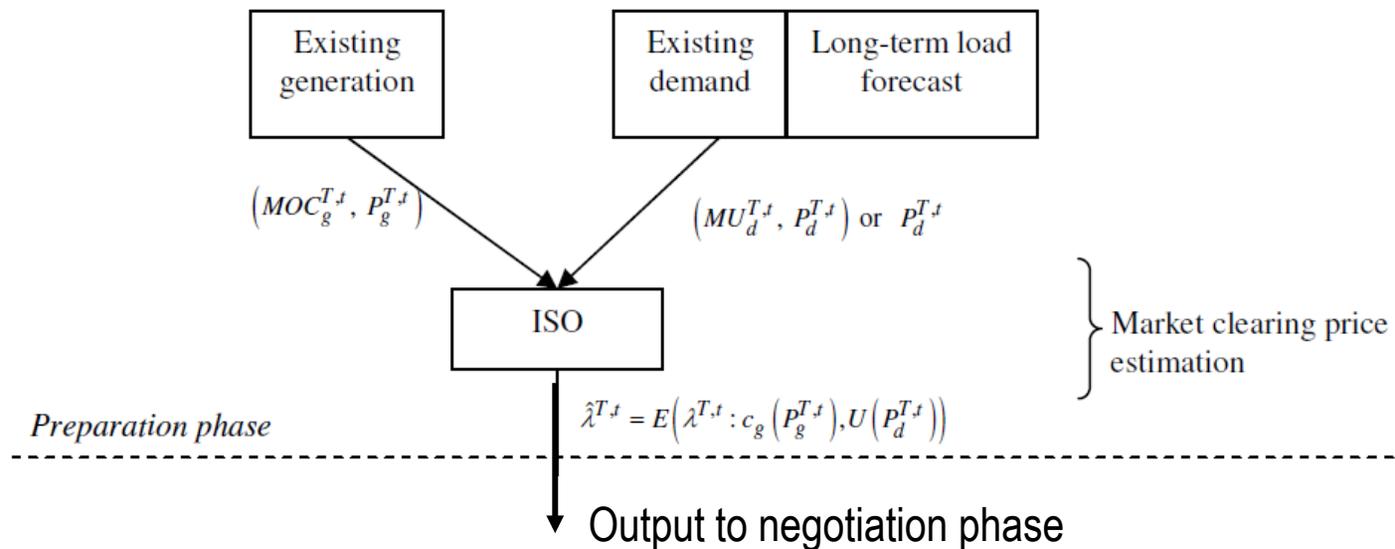
- Preparation phase
- Negotiation phase
- Commitment



Time line of different phases for a planning period that starts at y_0

Preparation phase

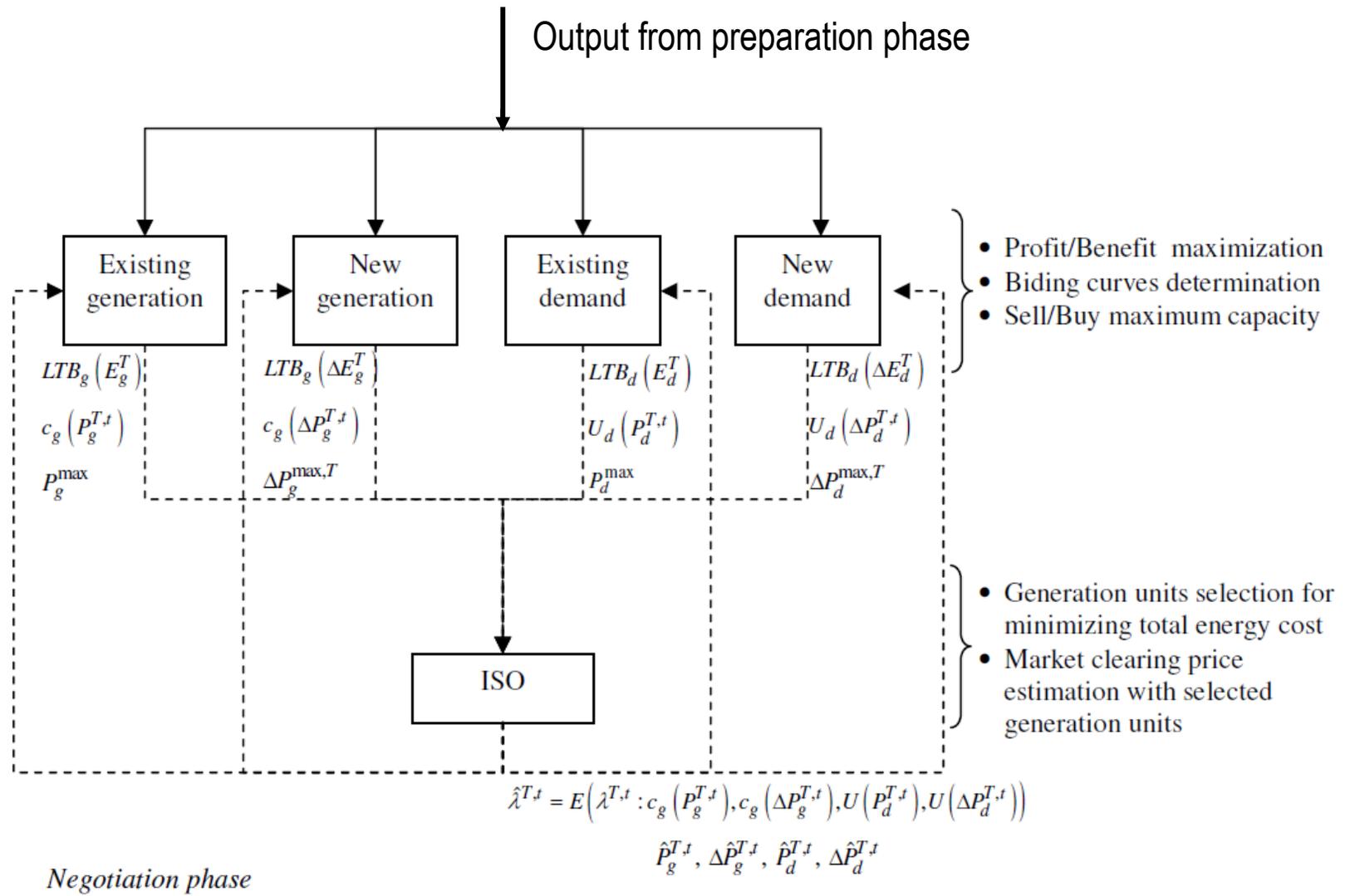
Step 1: During the preparation phase, ISO collects data from existing participants and estimates future MCP and distributes it to all existing and possible new market participants.



Negotiation phase

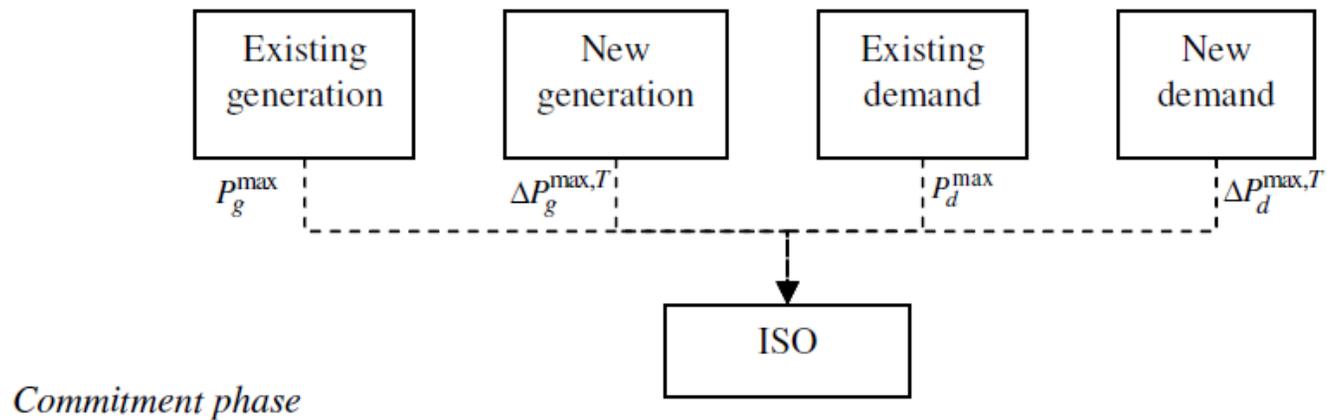
- Step 2:** During the negotiation phase, each generator maximizes its own profit based on the received MCP and designs short-run and long-run generation bidding functions.
- Step 3:** During the negotiation phase, each demand maximizes its own benefit based on the received MCP and designs short-run and long-run demand bidding functions.
- Step 4:** During the negotiation phase, ISO collects long-run bid functions from the existing and new participants, clears both long-term and short-term markets based on the bids offered by the market participants, estimates the likely future MCPs, and distributes bidding information to all participants.
- Step 5:** During a negotiation phase, information is interactively exchanged between participants and ISO until they reach a common decision.

Negotiation phase



Commitment phase

Step 6: During the commitment phase, all participants commit to buy/sell power quantity at long-run market price.



ISO decision process

■ Annual long-term market

$$\min_{E_g^T} \sum_{T=1}^{T_H} \rho^{-T} \left\{ \sum_{g=1}^{n_g} LTB_g(E_g^T) - LTB_d(E_d^T) \right\}$$

$$\text{Subject to: } \sum_{g=1}^{n_g} E_g^T \geq E_d^T \quad \sum_{g=1}^{n_g} P_g^{\max} + \sum_{g=1}^{n_g} \Delta P_g^T \geq P_d^{T,\max}$$

Available
units

■ Economic dispatch

$$\max_{P_d^{T,t}, P_g^{T,t}} \sum_{T=1}^{T_H} \rho^{-T} \left[\sum_{t=1}^{n_t} \left\{ U(P_d^{T,t}) - \sum_{g=1}^{n_g} c_g(P_g^{T,t}) \right\} \cdot t_{duration}^t \right]$$

$$\text{Subject to: } \sum_{g=1}^{n_g} P_g^{T,t} = P_d^{T,t} \quad 0 \leq P_g^{T,t} \leq P_g^{\max} + \Delta P_g^T$$

$\lambda^{T,t}$
 $P_d^{T,t}$
 $P_g^{T,t}$

Generator decision process

■ Profit maximization

$$\max_{P_g^{T,t}, \Delta P_g^T} \sum_{T=1}^{T_H} \rho^{-T} \left[\sum_{t=1}^{n_t} \left\{ \lambda^{T,t} \cdot P_g^{T,t} - c_g \left(P_g^{T,t} \right) \right\} t_{duration}^t - C_g \left(\Delta P_g^T \right) \right]$$

$$\text{Subject to: } P_g^{T,t} \leq P_g^{\max} + \Delta P_g^T$$

■ Long-run bidding function design

$$LRB_g^T [\$/MWh] = TAEC_g^T / E_g^T$$

$$E_g^T = \sum_{t=1}^{n_t} \left(P_g^{T,t} \cdot t_{duration}^t \right)$$

$$TAEC_g^T = \sum_{t=1}^{n_t} \left(c_g \left(P_g^{T,t} \right) t_{duration}^t \right) + C_g \left(\Delta P_g^T \right)$$

$$TAEC_g^T = \sum_{t=1}^{n_t} \left(c_g \left(P_g^{T,t} \right) t_{duration}^t \right) + C_g \left(\Delta P_g^T \right) RoR$$

$$TAEC_g^T = \sum_{t=1}^{n_t} \left(\lambda^{T,t} \cdot P_g^{T,t} \cdot t_{duration}^t \right) + C_g \left(\Delta P_g^T \right)$$

$$TAEC_g^T = \sum_{t=1}^{n_t} \left(\lambda^{T,t} \cdot P_g^{T,t} \cdot t_{duration}^t \right)$$

Demand decision process

- Utility maximization

$$\max_{P_d^{T,t}, \Delta P_d^T} \sum_{T=1}^{T_H} \rho^{-T} \left[\sum_{t=1}^{n_t} \left\{ U \left(P_d^{T,t} \right) - \lambda^{T,t} \cdot P_d^{T,t} \right\} t_{duration}^t \right] - C_d(\Delta P_d^T)$$

Subject to: $0 \leq P_d^{T,t} \leq P_d^{\max} + \Delta P_d^T$

- Long-run bidding function design

$$LRB_d^T [\$/MWh] = TAEB_d^T / E_d^T$$

$$TAEB_d^T = \sum_{t=1}^{n_t} \left(U_d \left(P_d^{T,t} \right) t_{duration}^t \right) - C_d \left(\Delta P_d^T \right)$$

$$E_d^T = \sum_{t=1}^{n_t} \left(P_d^{T,t} \cdot t_{duration}^t \right)$$

Comparison of the existing models

| Pricing | Demand | Bidding function type | | | |
|------------|-----------|-----------------------|------------------|----------------|-------|
| | | f_1 | f_2 | f_3 | f_4 |
| Pay as bid | Inelastic | IPF \equiv LCP | IPF \equiv LCP | IPF \sim TPT | --- |
| Uniform | Inelastic | --- | --- | ---- | --- |
| Pay as bid | Elastic | --- | --- | --- | CPLP |
| Uniform | Elastic | --- | --- | ---- | --- |

- IPF provide incentives to new investments because it gives generator owners the possibility to recover capital investments
- The IPF results in the same optimal solution as the LCP (inelastic demand).
- The IPF results in the same optimal solution as the CPLP (elastic demand)

Conclusions

We have proposed an efficient, long-term planning framework and model-based market design that defines necessary data transparency and information exchange in support of investments in different electrical power generation technologies.

Our hypothesis is that investment effectiveness of the changing industry in both new and old technologies will depend on the type of information available, the time horizon over which the information is exchanged, and whether the information is binding or not.

Multi-objective optimization gives the planner an option to select the best possible plan based on the trade-off between different objectives.

Conclusions

The IPF framework is shown to:

- Provide incentives to new investments because it gives generators owners a possibility to recover capital investments
- The IPF will result in the same optimal solution as the LCP in the case of inelastic demand
- The IPF will result in the same optimal solution as the CPLP. For this case there is a break-even point between annual capital cost and cumulative operating and maintenance cost over each year

Next steps

- We recognize that the planning problem is far from being a deterministic problem; the long-term system conditions are unlikely to be known with high confidence.
- Our proposed interactive planning framework (IPF) lends itself to implementing such management of uncertainties over time and market participants.
- Simulations done to illustrate the deterministic version of IPF
- Stochastic Dynamic Programming Challenge to Assess Value at Risk—huge computational challenge