Case Study: Hybridizing Nuclear Energy Systems in the U.S.

Mark F. Ruth

Joint ICTP-IAEA VIRTUAL Course on Nuclear–Renewable Integrated Energy Systems: Phenomenology, Research and Development

October 7, 2021

Team

- Bethany Frew, Daniel Levie, and Jal Desai (NREL);
- L. Todd Knighton, Dan Wendt, Cristian Rabiti, James Richards, Richard Boardman, and Shannon Bragg-Sitton (Idaho National Laboratory);
- Amgad Elgowainy (Argonne National Laboratory);
- Dan Ludwig (Xcel Energy)

Project Goal

Evaluate the Potential for Hybridized Nuclear Power Plants to Economically Generate Hydrogen – One Aspect of the H2@Scale Vision

Quantify the potential financial impact of hybridizing Xcel Energy's Prairie Island and Monticello nuclear power plants to produce hydrogen

Credit: Xcel Energy

Credit: Xcel Energy

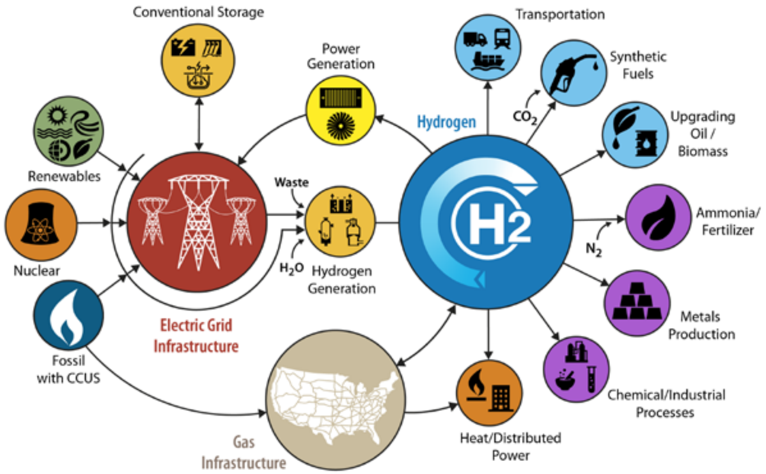
Additional Objectives

Evaluate the Potential for Hybridized Nuclear Power Plants to Economically Generate Hydrogen – One Aspect of the H2@Scale Vision

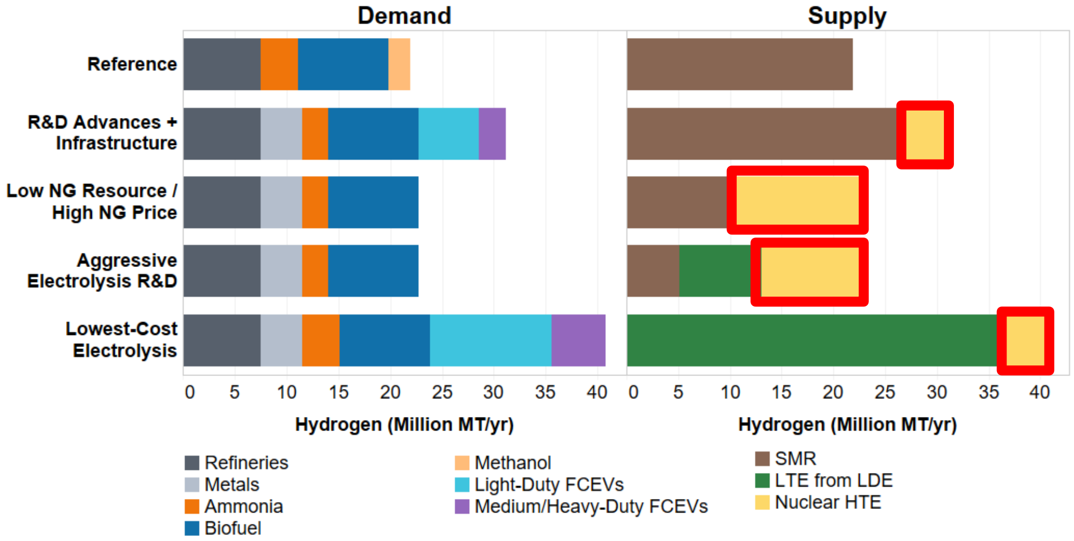
- Provide investment grade information for supporting Xcel Energy's greenhouse gas (GHG) reduction efforts to be used for internal and external stakeholder reviews and approvals.
- Quantify opportunity while considering impacts on generation required to meet all loads in the region
- Improve understanding of the potential for hybridized nuclear power plants to achieve the $2/kg hydrogen production cost target
- Develop tools and capabilities that better characterize hybridized hydrogen production on the grid so new opportunities can be analyzed.

Interest in Hydrogen

Using Nuclear Energy to Produce Hydrogen is a Key Opportunity for H2@Scale



https://www.energy.gov/eere/fuelcells/h2scale



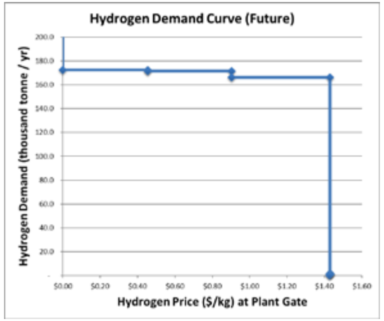
https://www.nrel.gov/docs/fy21osti/77610.pdf

Analysis of the economic potential of H2@Scale indicates that nuclear energy may provide a large quantity of hydrogen in the future (yellow bars in the righthand figure). This project is analyzing the economics of that opportunity

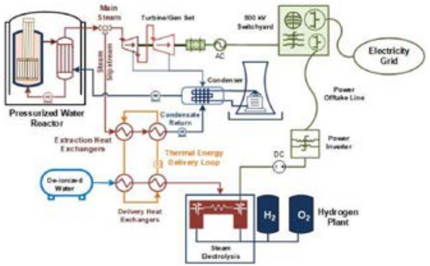
Overall Approach

Use Best-in-Class Analysis Tools and Transfer Information Between them to Address Analysis Questions

Hydrogen Market Assessment
(Delivery-adjusted demand curves)

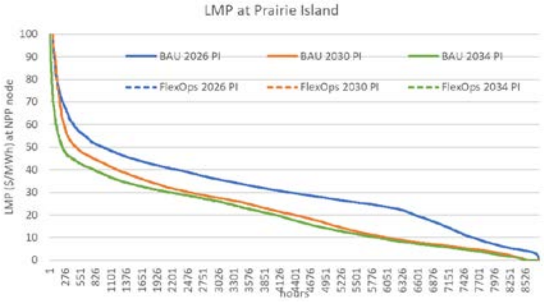


Hydrogen System Cost and Performance Estimates



Hydrogen System Configuration Optimization

In-depth electricity system modeling



	Annual APC	Annual NPP Net Operating Income	Annual System Wide Market Cost (Total)	Annual System Wide Market Cost (Net)
BAU 2026	516.1	151.3	835.5	835.5
BAU 2030	342.62	28.1	662.02	662.02
BAU 2034	237.7	-14.0	557.1	557.1
FlexOps 2026	518.0	151.9	837.4	837.4
FlexOps 2030	342.55	28.4	661.96	661.96
FlexOps 2034	236.7	-15.1	556.1	556.1
H2 2026				
H2 2030				
H2 2034				

Figures of Merit

Previous analyses* used a price-taker approach for grid modeling. This approach addresses the impacts of changing NPP generation on grid operations – essential to estimate impacts on an integrated utility like Xcel Energy.

* https://www.hydrogen.energy.gov/pdfs/review20/sa175_boardman_2020_p.pdf

Figures of Merit

1. **Annual Adjusted Production Cost (APC)**: total variable cost of non-NPP generation in Northern States Power (NSP) footprint, accounting for sales/purchases with neighboring zones (which may have different locational prices), summed across all hours.
   - Adapted from Midcontinent Independent System Operator (MISO) metric

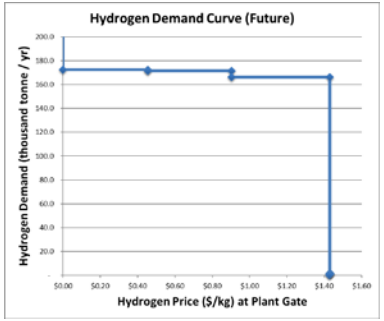
2. **Annual NPP Net Operating Income**: difference between the annual income (energy + operating reserves + H2) and annual operating cost (fixed costs + additional FlexOps cost) of an individual NPP
   - Standard pro forma calculation

3. **System-wide market costs**: APC plus Annual NPP Operating Cost. Two methods:
   A. Total Cost – do not include H2 revenue (i.e., does not benefit end rate payers)
   B. Net Cost – include H2 revenue (i.e., benefits end rate payers)

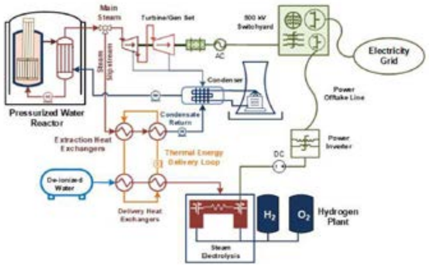
Overall Approach

Use Best-in-Class Analysis Tools and Transfer Information Between them to Address Analysis Questions

Hydrogen Market Assessment (Delivery-adjusted demand curves)

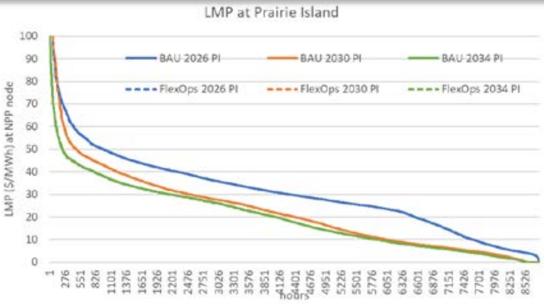


Hydrogen System Cost and Performance Estimates



Hydrogen System Configuration Optimization

In-depth electricity system modeling



	Annual APC	Annual NPP Net Operating Income	Annual System Wide Market Cost (Total)	Annual System Wide Market Cost (Net)
BAU 2026	516.1	151.3	835.5	835.5
BAU 2030	342.62	28.1	662.02	662.02
BAU 2034	237.7	-14.0	557.1	557.1
FlexOps 2026	518.0	151.9	837.4	837.4
FlexOps 2030	342.55	28.4	661.96	661.96
FlexOps 2034	236.7	-15.1	556.1	556.1
H2 2026				
H2 2030				
H2 2034				

Figures of Merit

Previous analyses* used a price-taker approach for grid modeling. This approach addresses the impacts of changing NPP generation on grid operations – essential to estimate impacts on an integrated utility like Xcel Energy.

* https://www.hydrogen.energy.gov/pdfs/review20/sa175_boardman_2020_p.pdf

Approach

Demand Curve Development Methodology

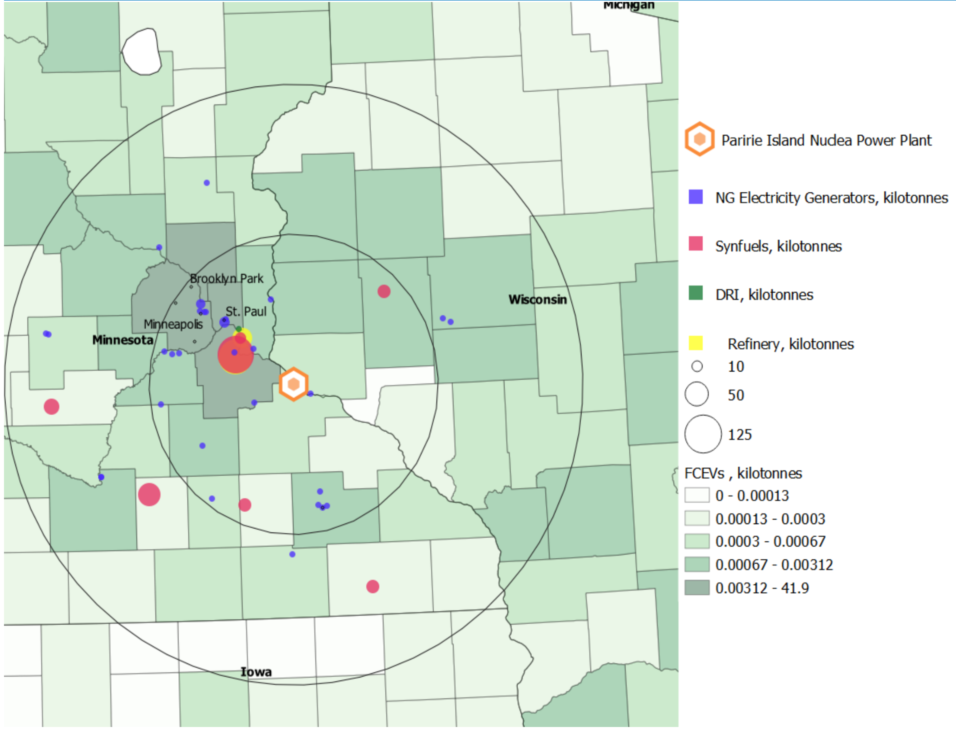
- Hydrogen demand for refineries: based on reported average H_2 use/BBL of crude processed at refinery
- Hydrogen for steel refining (direct reduction of iron - DRI): based on capacity of exiting steel plants, assuming 30 kg_H_2/MT of steel (i.e., 30% H_2/70% NG by energy)
- Hydrogen for synthetic hydrocarbon production: based on CO_2 available from adjacent ethanol plants and 3:1 H_2:CO_2 mole ratio
- Hydrogen for blending with natural gas for power generation: assuming 30% blending ratio by volume

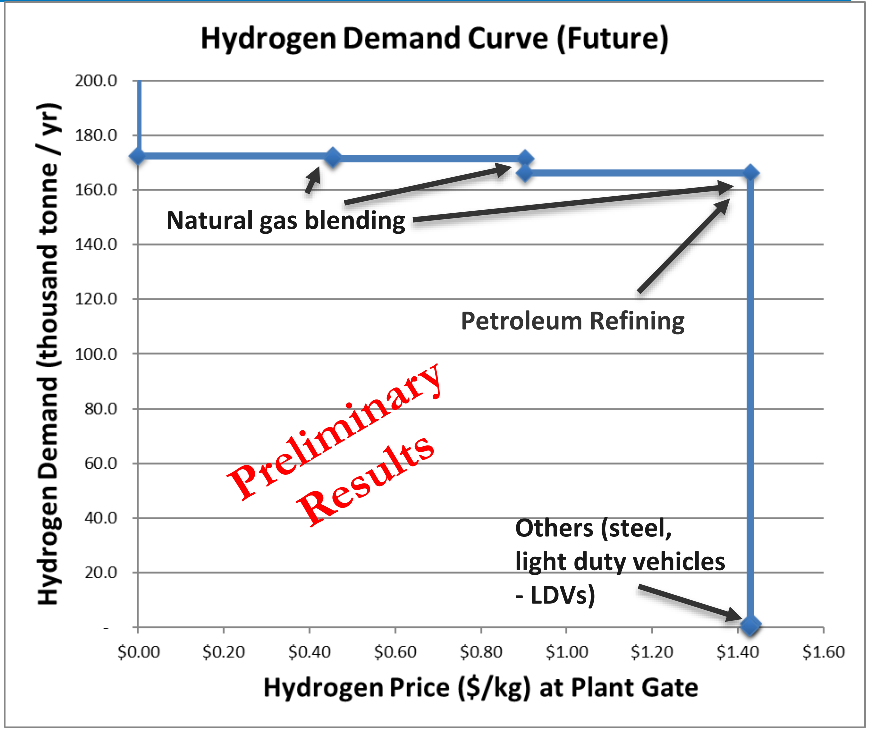
✓ Demand curve is adjusted with H_2 compression and delivery cost

✓ Threshold H_2 price set to breakeven with steam methane reformed-H_2 for refineries, fuel cell electric vehicles and DRI, and to breakeven with NG on (higher heating value - HHV) Btu cost basis for blending

  ➢ Assumed $22.2 tax per metric ton of CO_2

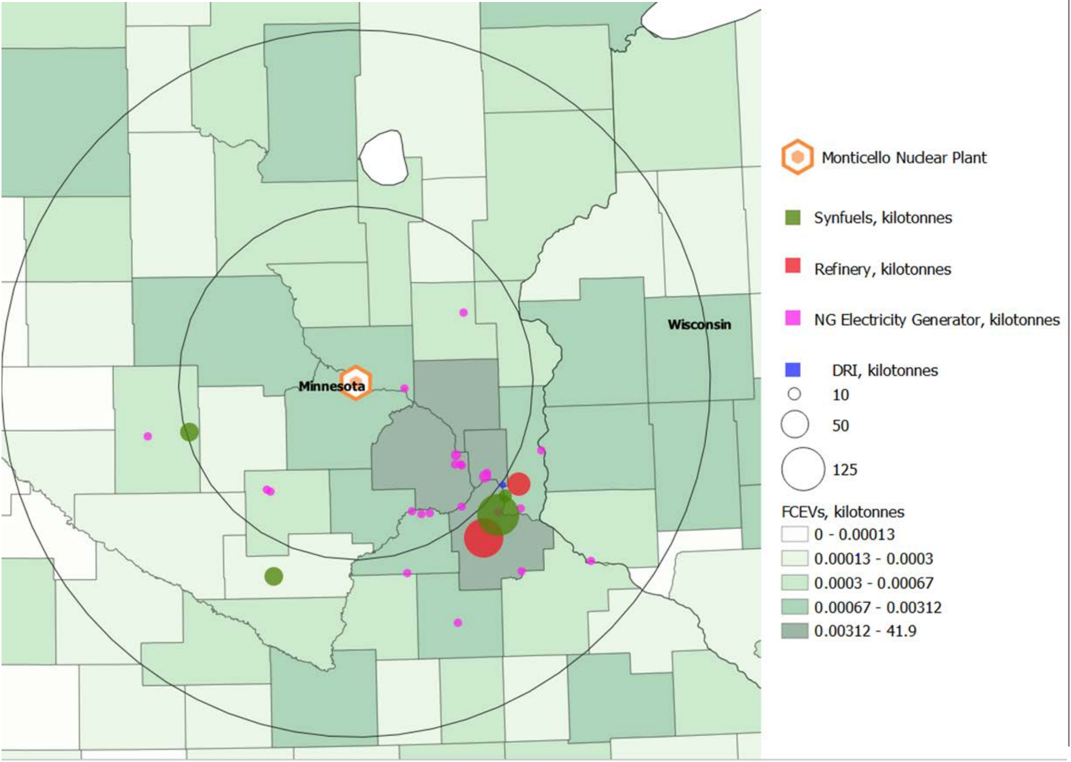
H2 Applications and Developed Delivery-& Carbon Cost-Adjusted Demand Curves for Prairie Island

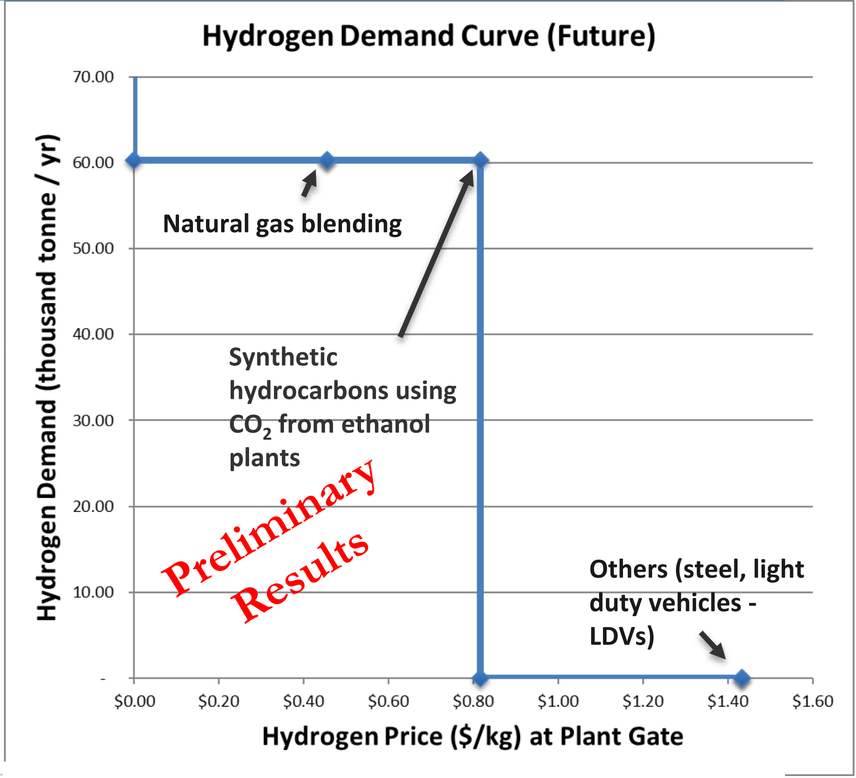




Primary hydrogen demands: petroleum refining and blending for power generation

H2 Applications and Developed Delivery-& Carbon Cost-Adjusted Demand Curves for Monticello



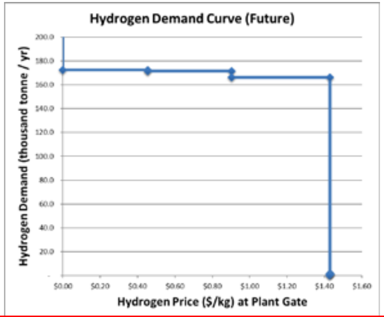


Delivery adjusted demand curve for Monticello shown on right

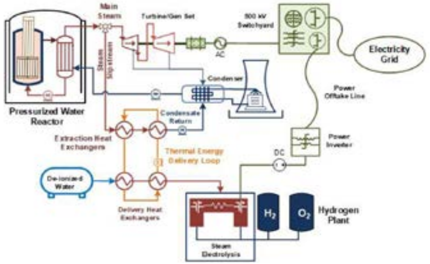
Overall Approach

Use Best-in-Class Analysis Tools and Transfer Information Between them to Address Analysis Questions

Hydrogen Market Assessment
(Delivery-adjusted demand curves)

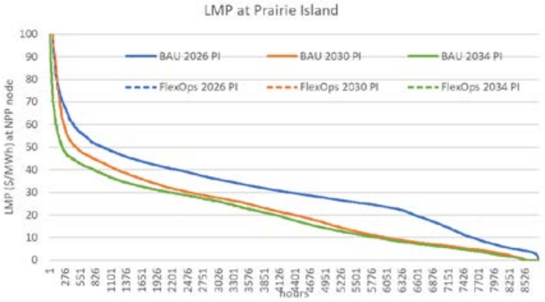


Hydrogen System Cost and Performance Estimates



Hydrogen System Configuration Optimization

In-depth electricity system modeling



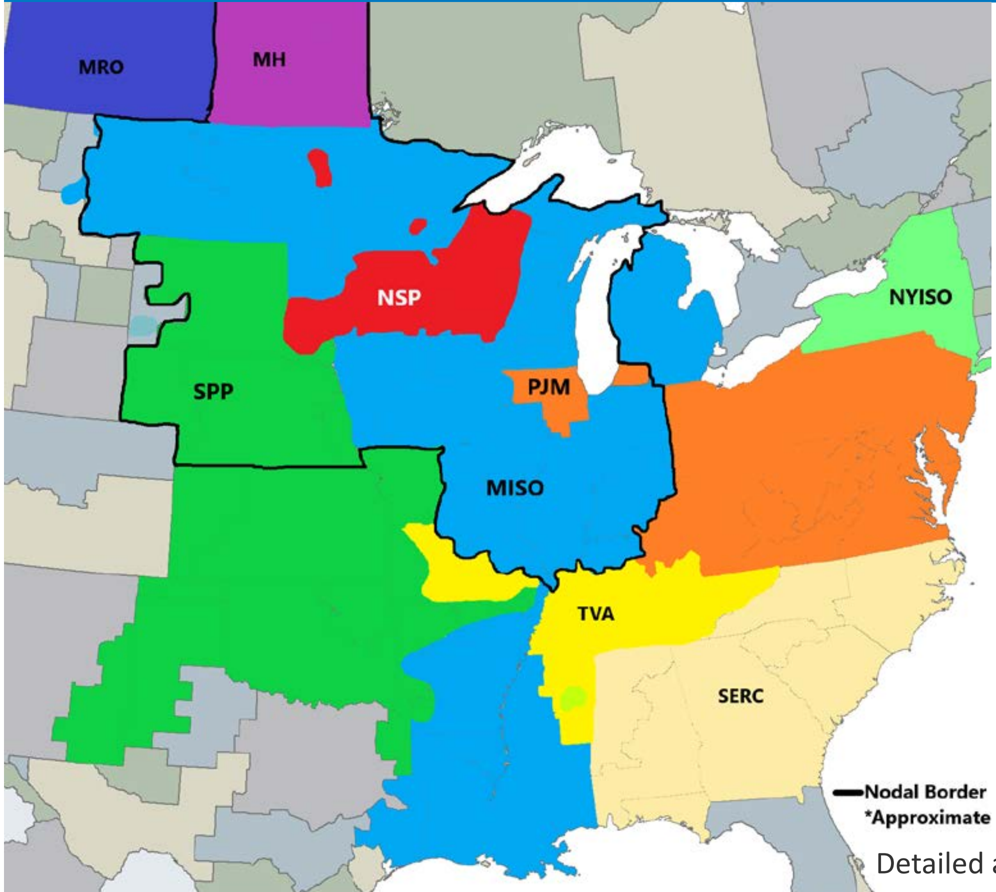
	Annual APC	Annual NPP Net Operating Income	Annual System Wide Market Cost (Total)	Annual System Wide Market Cost (Net)
BAU 2026	516.1	151.3	835.5	835.5
BAU 2030	342.62	28.1	662.02	662.02
BAU 2034	237.7	-14.0	557.1	557.1
FlexOps 2026	518.0	151.9	837.4	837.4
FlexOps 2030	342.55	28.4	661.96	661.96
FlexOps 2034	236.7	-15.1	556.1	556.1
H2 2026				
H2 2030				
H2 2034				

Figures of Merit

Previous analyses* used a price-taker approach for grid modeling. This approach addresses the impacts of changing NPP generation on grid operations – essential to estimate impacts on an integrated utility like Xcel Energy.

* https://www.hydrogen.energy.gov/pdfs/review20/sa175_boardman_2020_p.pdf

Electricity System Modeling: Nodal Hourly Production Cost Models for NSP and Zonal for Neighboring Regions



- Generation and transmission
  - Xcel Energy's Integrated Resource Plan within the Northern States Power (NSP) Territory
  - ReEDS capacity expansion model results for other regions
- Operating strategy and costs
  - PLEXOS Production Cost Modeling
  - Nodal resolution within the black boundary: 15,605 nodes with full unit commitment and operating reserves representation
  - All other zones: zonal resolution (i.e., copperplate inside of zone), no unit commitment, and generally no operating reserves

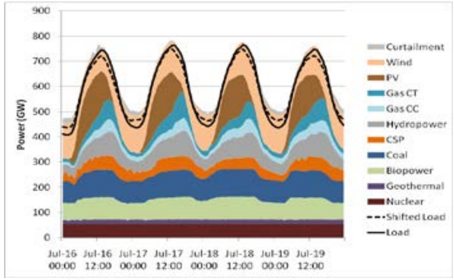
Detailed approach for grid modeling in supplemental slides

PLEXOS modeling for hourly system operation

- **Commercial-grade production cost software**
- **Hourly chronological optimization**
  - Minimizes system wide variable cost
- **Commits and dispatches generating units based on:**
  - Electricity demand
  - Operating parameters of generators (ramp rates, minimum generation level, outages, etc.)
  - Transmission grid parameters (flow limits, contingencies)
  - Operating reserve requirements
- **Used for system generation and transmission planning**
  - Increasingly used for real-time operation

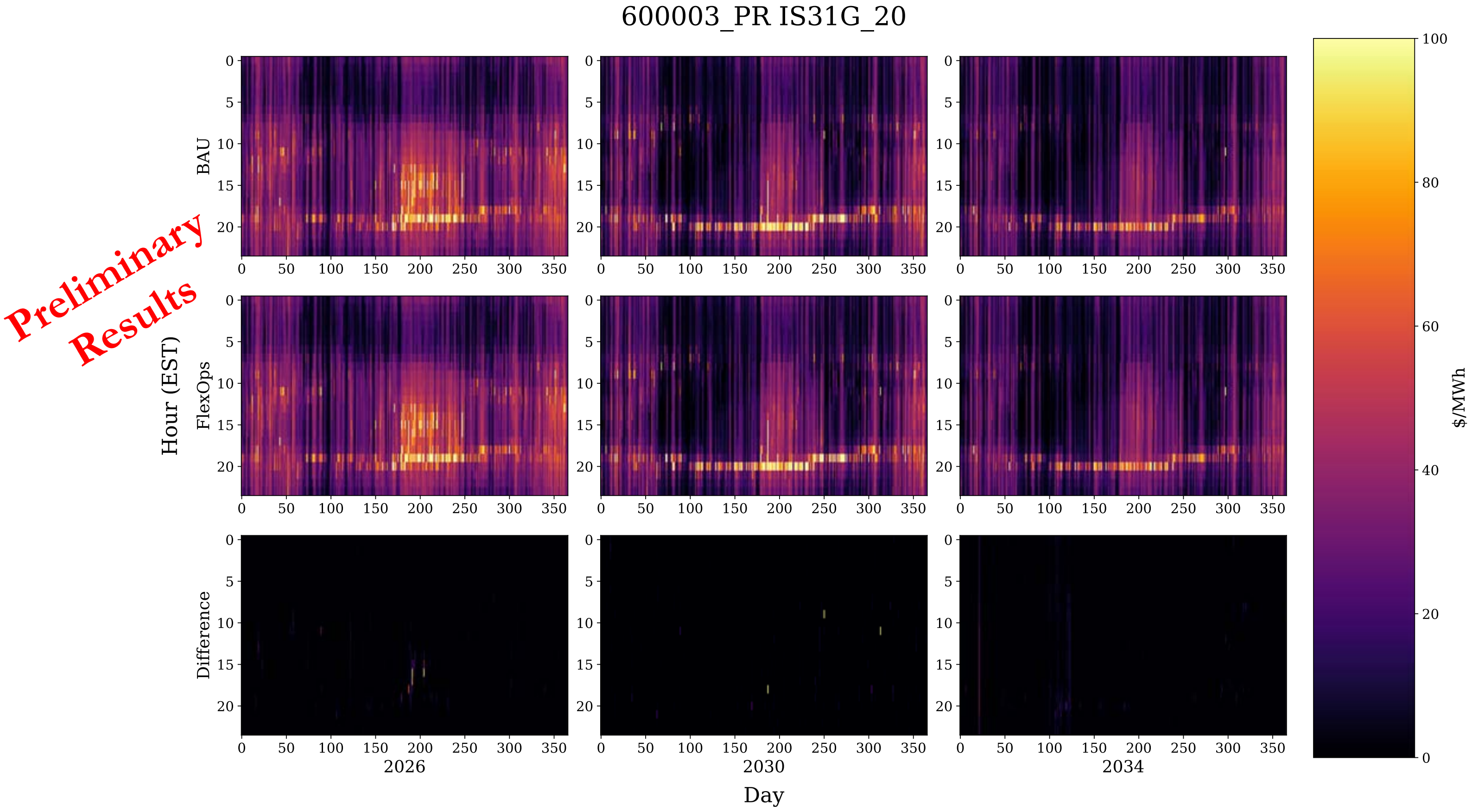
Locational prices, production cost

Dispatch information, curtailment, fuel usage

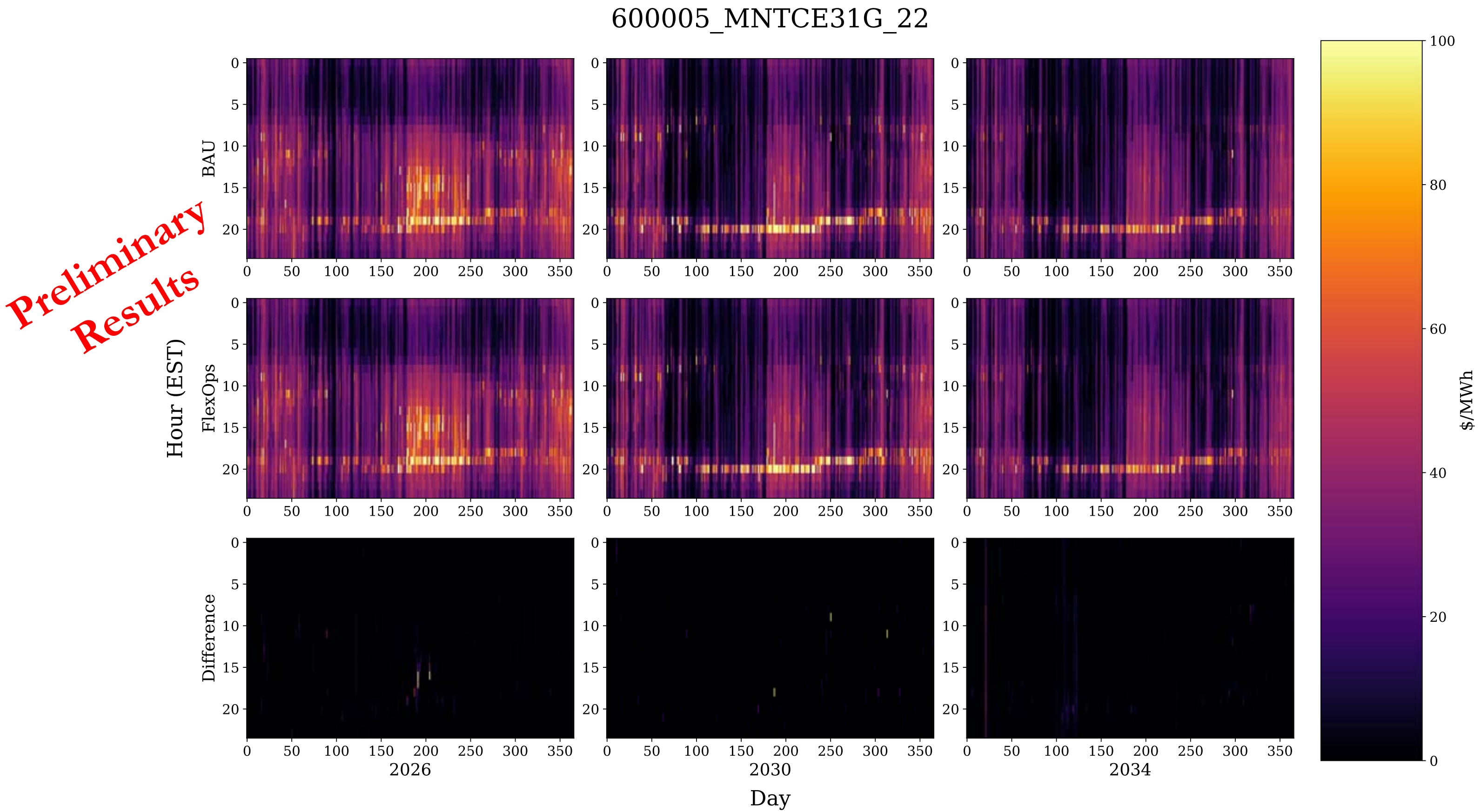


Transmission congestion

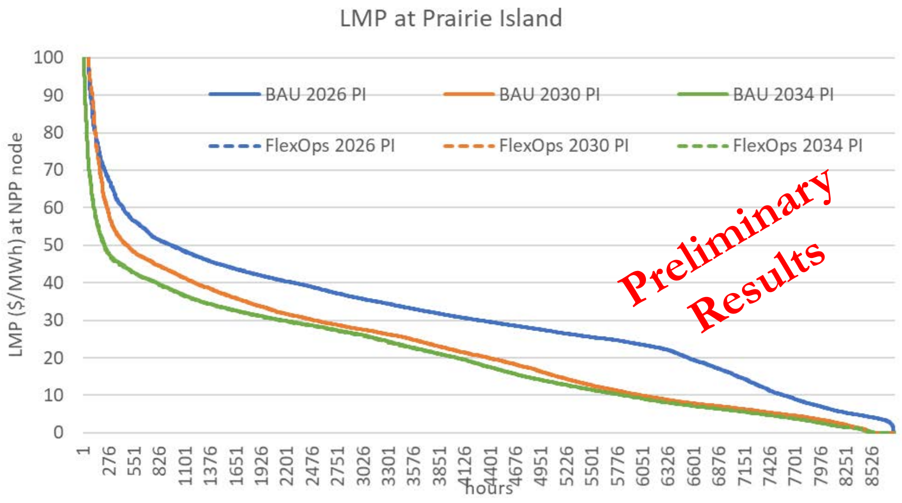
Prairie Island LMP Heat Map

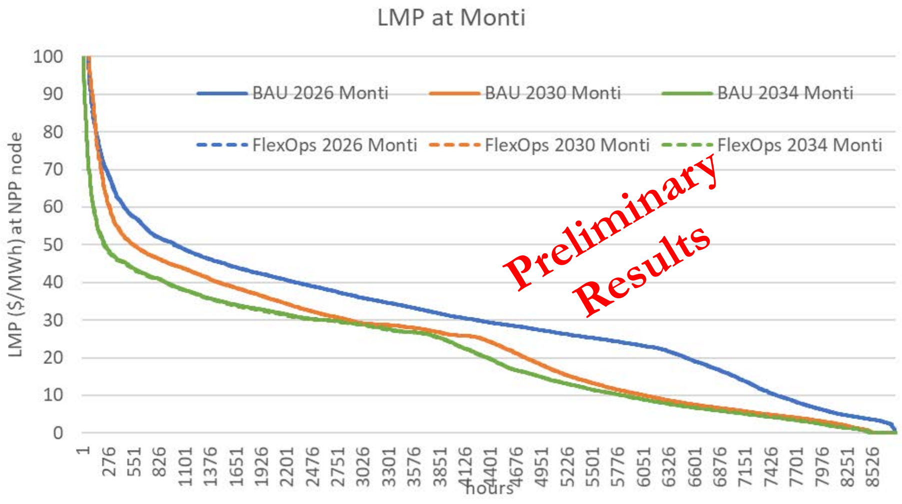


Monticello LMP Heat Map



Price Duration Curves

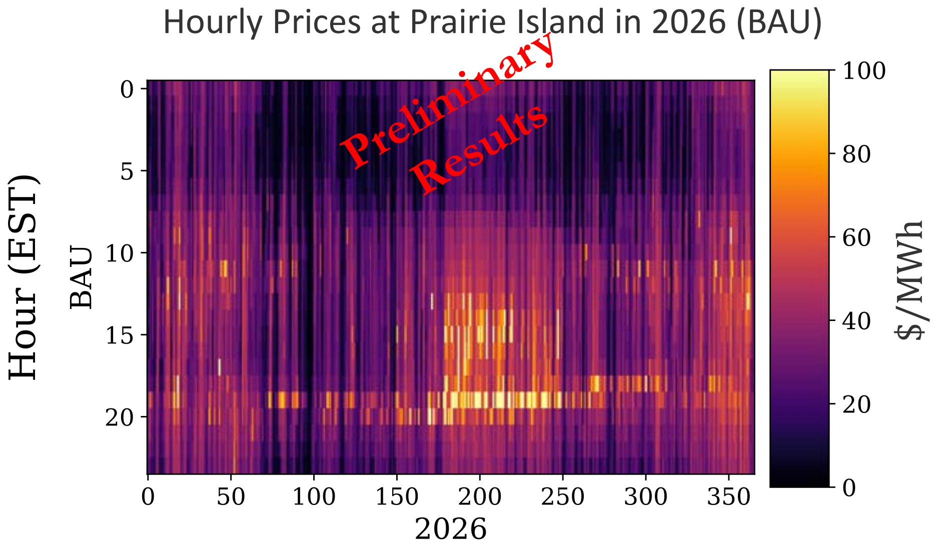


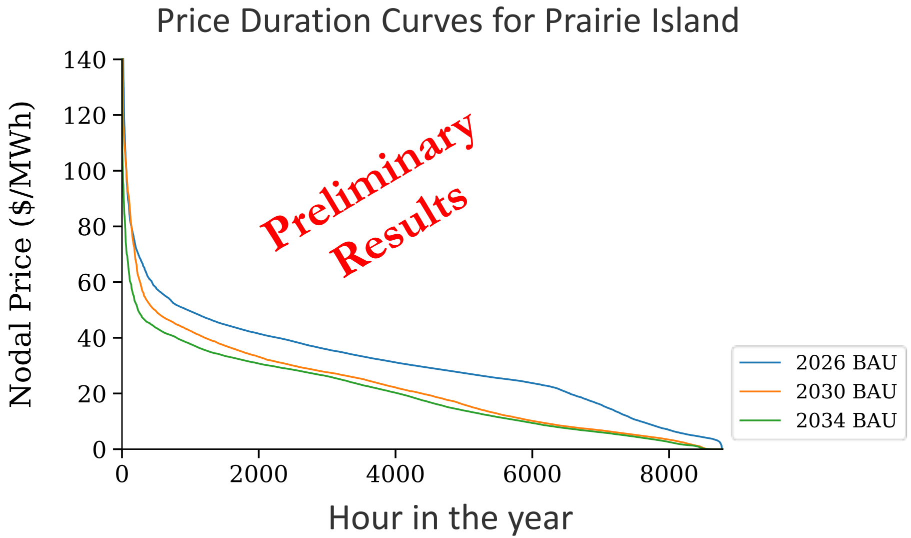


Minimum prices across the scenarios range from -0.00005 to -0.41 $/MWh (just negative enough to cause the NPPs to flex)

Used Production Cost Modeling to Estimate Hourly Locational Marginal Prices (LMPs)

Estimated LMPs for each hour of the years 2026, 2030, and 2034 at both NPPs under business-as-usual (BAU) (must-run) and FlexOps (reduce generation when revenue<cost – i.e., LMP<$0/MWh) operating strategies.



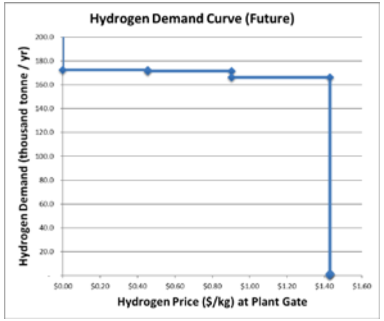


Ramping is minimal (<48 hours/yr) in FlexOps scenarios over all years

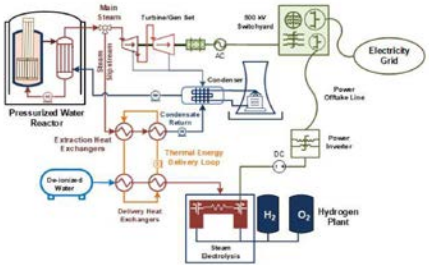
Overall Approach

Use Best-in-Class Analysis Tools and Transfer Information Between them to Address Analysis Questions

Hydrogen Market Assessment
(Delivery-adjusted demand curves)

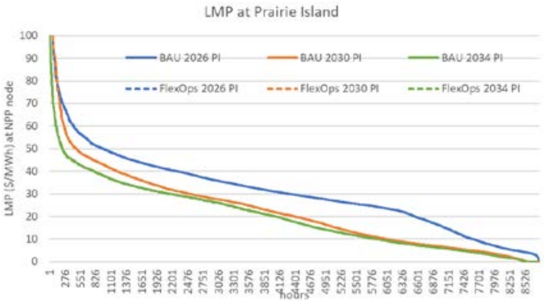


Hydrogen System Cost and Performance Estimates



Hydrogen System Configuration Optimization

In-depth electricity system modeling



	Annual APC	Annual NPP Net Operating Income	Annual System Wide Market Cost (Total)	Annual System Wide Market Cost (Net)
BAU 2026	516.1	151.3	835.5	835.5
BAU 2030	342.62	28.1	662.02	662.02
BAU 2034	237.7	-14.0	557.1	557.1
FlexOps 2026	518.0	151.9	837.4	837.4
FlexOps 2030	342.55	28.4	661.96	661.96
FlexOps 2034	236.7	-15.1	556.1	556.1
H2 2026				
H2 2030				
H2 2034				

Figures of Merit

Previous analyses* used a price-taker approach for grid modeling. This approach addresses the impacts of changing NPP generation on grid operations – essential to estimate impacts on an integrated utility like Xcel Energy.

* https://www.hydrogen.energy.gov/pdfs/review20/sa175_boardman_2020_p.pdf

Approach

HTSE Cost and Performance Characterization

HTSE Cost and Performance Characterization

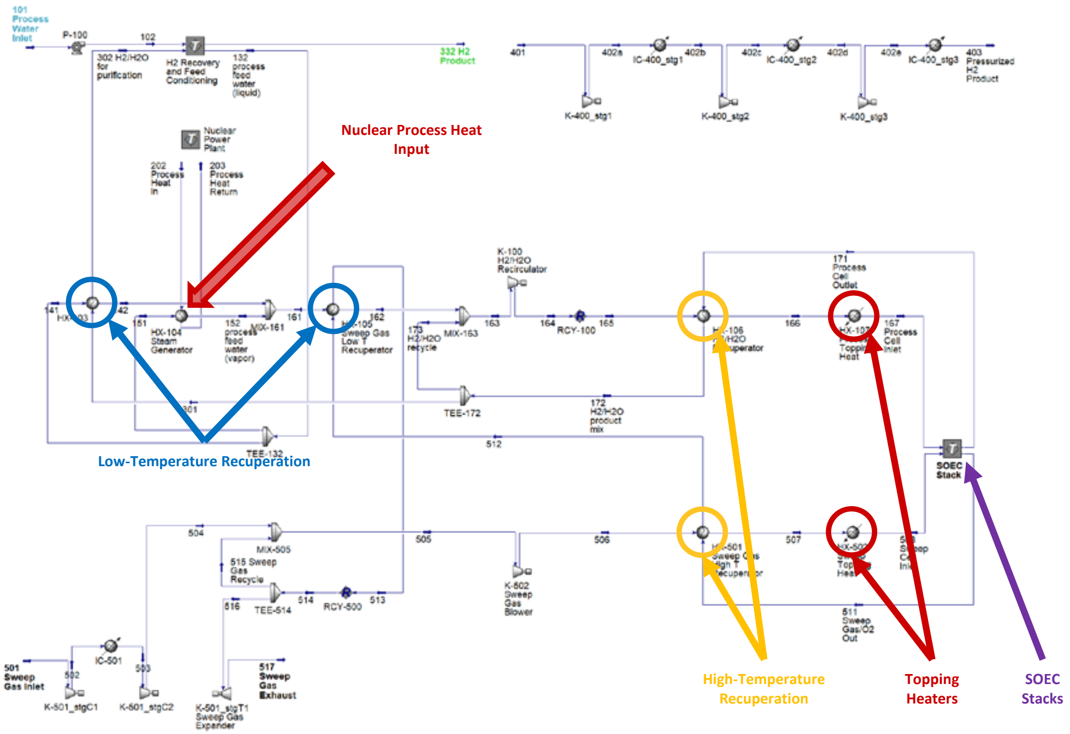
- Light Water Reactor (LWR)-integrated HTSE process model developed using AspenTech HYSYS software to evaluate system mass & energy balances; model results used as basis for calculation of system performance parameters including specific energy consumption and system efficiency
  - Thermal Delivery Loop (TDL) used to supply LWR nuclear process heat for HTSE process feed water vaporization
  - Electrical power supplied by LWR for electrolyzer and balance of plant power demands; LWR power cycle model used to estimate reduction in electrical power generation resulting from diverting LWR power cycle steam to TDL to meet HTSE plant thermal demands.
- System capital costs obtained based on equipment sizing parameters computed by HYSYS process model. AspenTech Process Economic Analyzer and cost data from previous HTSE system design reports used to estimate HTSE system capital costs for present analysis.
  - Modular construction system design basis: 25 MW-dc HTSE modules assembled in offsite manufacturing facility and installed in parallel to achieve specified H_2 production capacity. Each HTSE module specified to include feed stream conditioning, heat recuperation, product purification, and sweep gas supply equipment. Cost reductions for modular components achieved through economies of mass production; 95% learning curve used to estimate modular system component costs for Nth-of-a-kind HTSE plant.
  - Scalable (non-modular) equipment used to provide nuclear process heat to HTSE modules, high-pressure compression of hydrogen product, and common plant support functionality (water purification, process control, etc.). Scalable equipment sizing varies with HTSE plant capacity, and capital cost reductions are realized through conventional economies of scale

Parameter	Large Scale Production System Design Basis
Stack Operating T	800°C [1]
Stack Operating P	**5 bar**
Cell Voltage	**1.285 V/cell**
Stack Inlet H_2O Composition	90 mol% [1]
Steam Utilization	**80%**
Cell Area	144 cm² [1]
HTSE modular block capacity	25 MW-dc (1000x capacity increase from [1])
Cells per HTSE modular block	**136,000**
Current Density	**1.0 A/cm²**
Area Specific Resistance	0.375 Ω-cm²
Operating Mode	Constant V
Sweep Gas	Air [1]
Sweep Gas Inlet Flow Rate	Flow set to achieve 40 mol% O_2 in anode stream outlet
H_2 Product Purity	99.9 mol%
H_2 Product Pressure	69 bar (1000 psi)
TDL Heat Transfer Fluid	Therminol-66 [2,3]
TDL transport distance	1.0 km [4]

[1] O'Brien et al, Intl J Hydrogen Energy 45 (2020)
[2] O'Brien et al, INL/EXT-17-43269 (2017)
[3] Frick et al, INL/CON-18-46075 (2019)
[4] Vedros et al, INL/EXT-20-60104 (2020)

Approach

HTSE Cost and Performance Characterization



Process Operating Mode Simulations

- Normal Operating Mode
  - Design point operating specifications listed in Table (right)
  - Constant voltage SOEC stack operating mode results in decrease in stack operating current associated with cell degradation; Effect of stack degradation captured in capacity factor specification - HTSE process availability (95%) x cell degradation adjustment factor (95.3%) = 90.5%
  - Economic model includes allowance for annual stack replacements to restore design capacity at the start of each operating year

- Hot Standby Operating Mode
  - Stack operating temperature, pressure, inlet composition, and inlet flow rate (process gas and sweep gas) maintained at nominal values using TDL steam generator, process and sweep gas blowers, electric topping heaters, and recycle of H_2/H_2O process gas from stack outlet and H_2 from product recovery
  - 0% stack power during hot standby mode; stack inlet and outlet compositions equal during hot standby operating mode (zero steam utilization)
  - H_2O component flow rate into product recovery subprocess maintained at design point value

Accomplishment

Updated High Temperature Steam Electrolysis (HTSE) Performance and Cost Estimates to Improve Characterization of "Hot Standby Mode" and Credibility

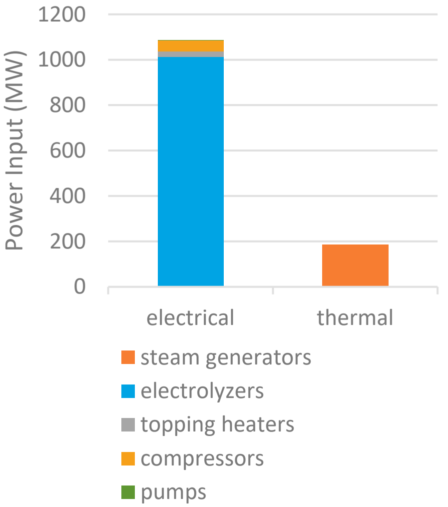
	Large Scale H_2 Production Design Basis
Plant Design Capacity	1086 MW-e
Design Hydrogen Production Capacity	697 tpd
Process Power Requirement, Normal Electrical Thermal	 1086 MW-ac 187 MW-t
Process Power Requirement, Hot Standby Electrical Thermal	 9.3 MW-ac (0.9% nominal) 35.5 MW-t (19% nominal)
Specific Energy Consumption Electrical Thermal	 37.4 kWh-ac/kg H_2 6.4 kWh-t/kg H_2
System H_2 Production Efficiency (energy content of product H_2 divided by electrical energy equivalent input)	88.9% HHV basis
System CAPEX (Nth-of-a-kind – NOAK)* Stack Cost Direct Capital Costs Total Capital Investment	 $155/kW-dc $514/kW-ac $656/kW-ac
Annual Operating & Maintenance (O&M) Costs* Fixed (labor, maintenance, overhead) Variable (stacks, water, energy excluded)	 $17.95/kWe-yr $5.06/MWh-e

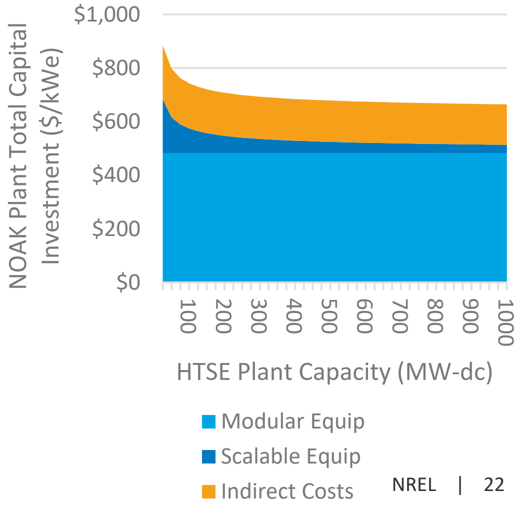
Preliminary Results

* 2016 USD, scales with plant capacity

Improved process modeling to better estimate energy requirements (including "Hot Standby" requirements)

Established non-proprietary capital cost estimates using stack costs based on HFTO HTSE H_2 Production Record and balance-of-plant equipment costs estimated from AspenTech Process Economic Analyzer and literature data sources

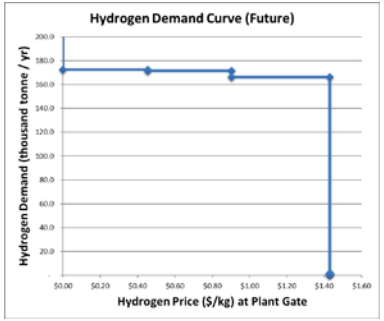




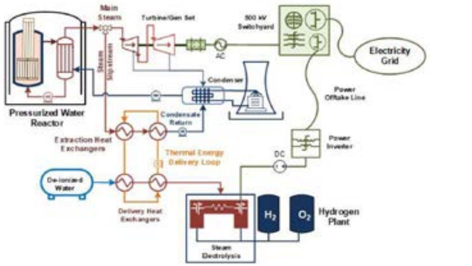
Overall Approach

Use Best-in-Class Analysis Tools and Transfer Information Between them to Address Analysis Questions

Hydrogen Market Assessment
(Delivery-adjusted demand curves)

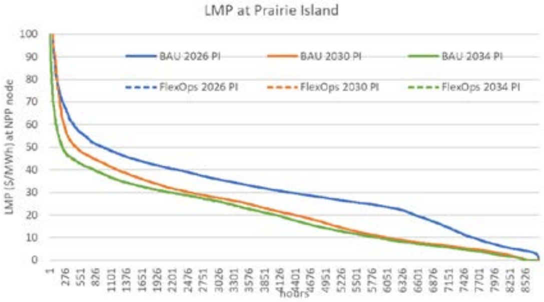


Hydrogen System Cost and Performance Estimates



Hydrogen System Configuration Optimization

In-depth electricity system modeling



	Annual APC	Annual NPP Net Operating Income	Annual System Wide Market Cost (Total)	Annual System Wide Market Cost (Net)
BAU 2026	516.1	151.3	835.5	835.5
BAU 2030	342.62	28.1	662.02	662.02
BAU 2034	237.7	-14.0	557.1	557.1
FlexOps 2026	518.0	151.9	837.4	837.4
FlexOps 2030	342.55	28.4	661.96	661.96
FlexOps 2034	236.7	-15.1	556.1	556.1
H2 2026				
H2 2030				
H2 2034				

Figures of Merit

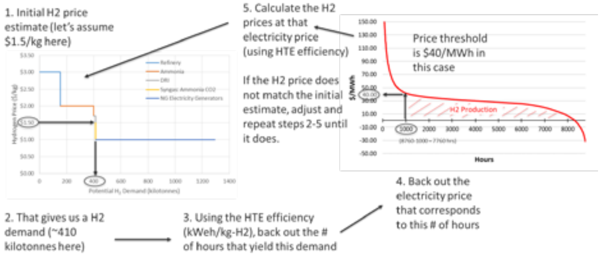
Previous analyses* used a price-taker approach for grid modeling. This approach addresses the impacts of changing NPP generation on grid operations – essential to estimate impacts on an integrated utility like Xcel Energy.

* https://www.hydrogen.energy.gov/pdfs/review20/sa175_boardman_2020_p.pdf

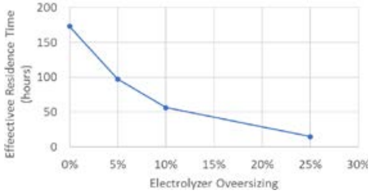
Price-Taker Co-optimization: Demand Curve, Electrolyzer Size, and Storage Size

- **H2 demand curve**
  - Sets “electricity price threshold”

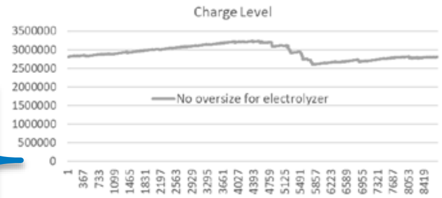
This is an outer loop for the below



- **Electrolyzer size**
  - Sets minimum and maximum generation
  - Tradeoff between electrolyzer capital cost and H2 production/storage/revenues



- **Storage size**
  - Tradeoff between storage capital cost, electrolyzer capital cost, H2 revenues, and constant H2 output constraint



→ **Final result**: fixed NPP generation profile that achieves an equilibrium between all of these dimensions

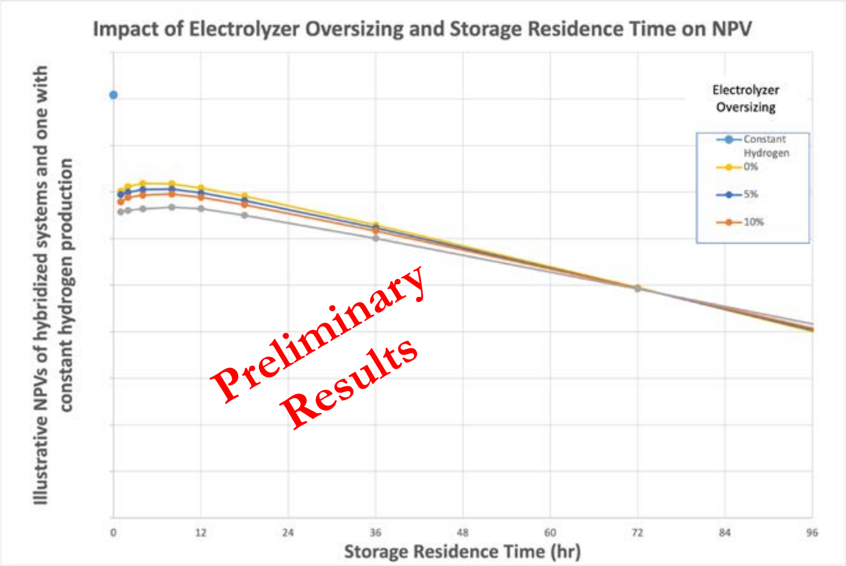
Accomplishment

Hybrid NPP Producing Hydrogen: Price-Taker Optimization Results

A hydrogen price greater than those in the demand curves is necessary to pay back a near-term investment.

Constant hydrogen production is found to be more profitable than hybridization. A later construction date increases the value of hybridization

When hybridized, net present value (NPV) is maximized with short storage residence times (4-8 hr) and minimum oversizing of the electrolyzer



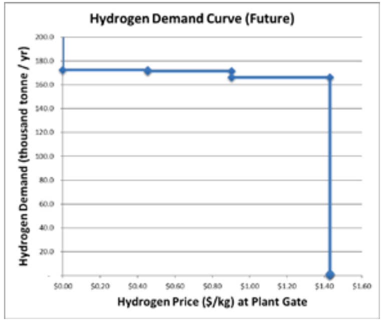
	Electrolyzer Size	Annual Hydrogen Sales	Capacity Factor in 2026
Constant Hydrogen	713 MW_e	166,100 kg/yr	98%
0% Oversizing	1,037 MW_e	143,608 kg/yr	58%
5% Oversizing	1,037 MW_e	136,769 kg/yr	56%
10% Oversizing	1,037 MW_e	130,552 kg/yr	54%
25% Oversizing	1,037 MW_e	114,886 kg/yr	48%

Preliminary Results

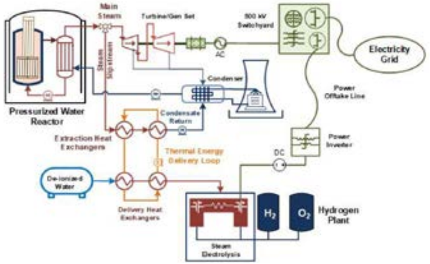
Overall Approach

Use Best-in-Class Analysis Tools and Transfer Information Between them to Address Analysis Questions

Hydrogen Market Assessment
(Delivery-adjusted demand curves)

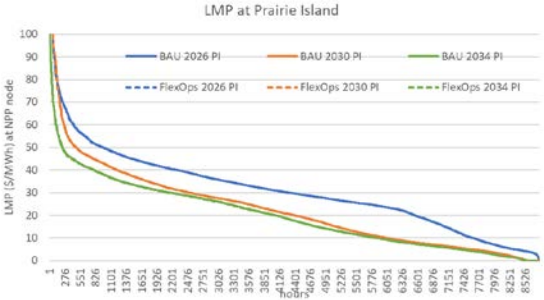


Hydrogen System Cost and Performance Estimates



Hydrogen System Configuration Optimization

In-depth electricity system modeling



	Annual APC	Annual NPP Net Operating Income	Annual System Wide Market Cost (Total)	Annual System Wide Market Cost (Net)
BAU 2026	516.1	151.3	835.5	835.5
BAU 2030	342.62	28.1	662.02	662.02
BAU 2034	237.7	-14.0	557.1	557.1
FlexOps 2026	518.0	151.9	837.4	837.4
FlexOps 2030	342.55	28.4	661.96	661.96
FlexOps 2034	236.7	-15.1	556.1	556.1
H2 2026				
H2 2030				
H2 2034				

Figures of Merit

Previous analyses* used a price-taker approach for grid modeling. This approach addresses the impacts of changing NPP generation on grid operations – essential to estimate impacts on an integrated utility like Xcel Energy.

* https://www.hydrogen.energy.gov/pdfs/review20/sa175_boardman_2020_p.pdf

Approach

Figure of Merit: Adjusted Production Cost

$$APC_{ann} = \sum_{h=1}^{8760} \overbrace{\sum_{\substack{g \in NSP \\ non-NPP gens}} V_{h,g}}^{\text{Generator variable cost (VO\&M, emissions, and fuel); do not include NPP or wind PTC values}} - \overbrace{N_h}^{\text{Net Exchange with NSP; + if export from NSP, - if import}} * \overbrace{ZP_h}^{\text{Weighted-average zonal energy price (LMP)}}$$

[$/hr] [MWh/h] [$/MWh]

where

- If NSP buys: $ZP_h = \frac{\sum_{i \in selling\ zone\ nodes} L_{h,i} * P_{h,i}}{\sum_{i \in selling\ zone\ nodes} L_{h,i}}$ Load-weighted- LMP of zone importing from

- If NSP sells: $ZP_h = \frac{\sum_{g \in NSPgens} G_{h,g} * P_{h,i}}{\sum_{g \in NSPgens} G_{h,g}}$ Generation-weighted- LMP of NSP zone

These values will all be taken from PLEXOS outputs

Approach

Figure of Merit: Annual NPP Net Operating Income

$$N_{NPP,ann} = \left\{ \sum_{h=1}^{8760} \overbrace{\left(\sum_{p=1}^{OpResNum} RP_{h,p} R_{h,p} \right)}^{\text{Operating Reserve Income (H2 scenario only)}} + \overbrace{EP_h G_h}^{\text{Energy Income}} + \overbrace{HP * H2_h}^{\text{H2 Income}} \right\} - \overbrace{C_{NPP,base}}^{\text{NPP fixed costs}} - \overbrace{\sum_{j=1}^{All\ hours\ operated\ in\ alternate\ conditions} O_{flex,j}}^{\text{Additional cost for Flex Ops}}$$

[$/MWh x MWh/h]

[$/MWh x MWh/h]

[$/kg x kg/h]

[$/yr]

[$/h]

These values will all be taken from PLEXOS outputs, with the addition of the H2 demand curve (H2 price for a given amount of H2 produced) from ANL

Approach

Figure of Merit: Annual System Wide Market Costs

Since Xcel NSP currently does not have a formal policy for how to incorporate the H2 revenues into rate case accounting, we calculate two variants to bookend the benefit that H2 revenues provide to the system wide market cost

A) **Total Annual System Wide Market Costs**:

$$C_{cust,tot} = APC_{ann} + \overbrace{C_{NPP,ann}}^{\text{annual cost to operate the NPP}} + \overbrace{C_{non-NPP,annFix}}^{\text{annual fixed cost to operate the non-NPP generators}}$$

[$/yr] [$/yr] [$/yr]

H2 revenues **do not help** to offset the cost that is passed on to the rate payers

B) **Net Annual System Wide Market Costs**:

$$C_{cust,net} = APC_{ann} + C_{NPP,ann} + C_{non-NPP,annFix} - \overbrace{\sum_{h=1}^{8760} HP * H2_h}^{\text{H2 revenues}}$$

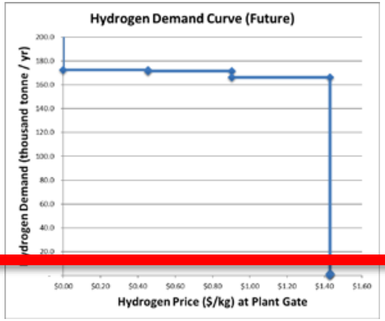
[$/yr] [$/yr] [$/yr] [$/kg x kg/h]

H2 revenues **help** to offset the cost that is passed on to the rate payers

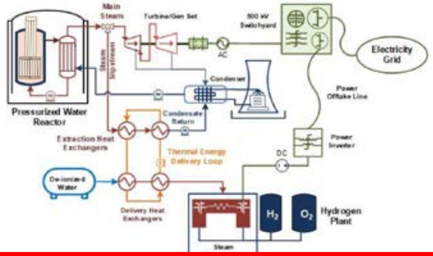
Overall Approach

Use Best-in-Class Analysis Tools and Transfer Information Between them to Address Analysis Questions

Hydrogen Market Assessment
(Delivery-adjusted demand curves)

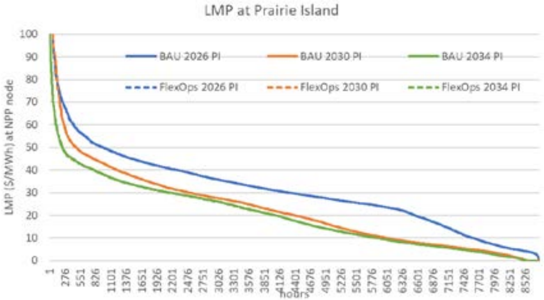


Hydrogen System Cost and Performance Estimates



Hydrogen System Configuration Optimization

In-depth electricity system modeling



	Annual APC	Annual NPP Net Operating Income	Annual System Wide Market Cost (Total)	Annual System Wide Market Cost (Net)
BAU 2026	516.1	151.3	835.5	835.5
BAU 2030	342.62	28.1	662.02	662.02
BAU 2034	237.7	-14.0	557.1	557.1
FlexOps 2026	518.0	151.9	837.4	837.4
FlexOps 2030	342.55	28.4	661.96	661.96
FlexOps 2034	236.7	-15.1	556.1	556.1
H2 2026				
H2 2030				
H2 2034				

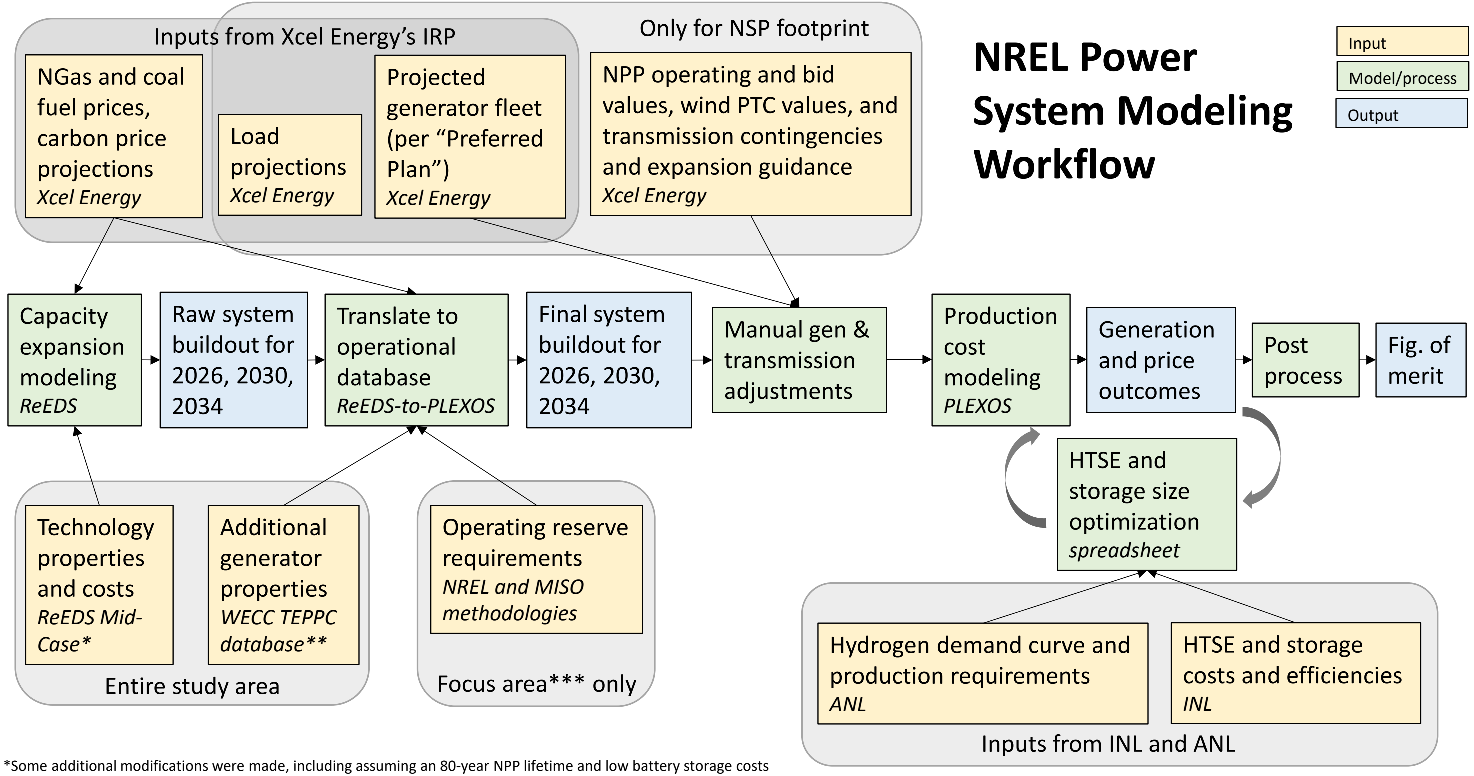
Figures of Merit

Previous analyses* used a price-taker approach for grid modeling. This approach addresses the impacts of changing NPP generation on grid operations – essential to estimate impacts on an integrated utility like Xcel Energy.

* https://www.hydrogen.energy.gov/pdfs/review20/sa175_boardman_2020_p.pdf

Approach

Detailed Workflow for Power System Modeling



*Some additional modifications were made, including assuming an 80-year NPP lifetime and low battery storage costs
**Including min up/down time, forced outage rates, start costs, minimum generation level, max ramp rates
***"Focus area" zones are run at a nodal resolution with full unit commitment and operating reserve representation

Preliminary Estimates of Figures of Merit for BAU and FlexOps Scenarios

Preliminary Results

	Annual APC	Annual NPP Net Operating Income	Annual System Wide Market Cost (Total)	Annual System Wide Market Cost (Net)
BAU 2026	516.1	151.3	835.5	835.5
BAU 2030	342.62	28.1	662.02	662.02
BAU 2034	237.7	-14.0	557.1	557.1
FlexOps 2026	518.0	151.9	837.4	837.4
FlexOps 2030	342.55	28.4	661.96	661.96
FlexOps 2034	236.7	-15.1	556.1	556.1
H2 2026				
H2 2030	**Under Development**			
H2 2034				

Values shown with more significant figures than is warranted by the method and data so that the viewer can see very small differences between results.

- All metrics decrease as between 2026 and 2034 due to an increase in lower marginal cost resources (e.g., wind and solar PV)
- FlexOps more favorable than BAU in 2030+2034
- NPP loses money in 2034 for both BAU & FlexOps due to a reduction in energy prices

Summary

- Multiple inputs are important to estimate the potential for hybridization
  - Existing and potential regional hydrogen markets
  - Future electricity market prices
  - Equipment costs and performance especially when operated flexibly (high temperature steam electrolyzers)
- Business structures and cases inform key metrics and potential for investments
  - Variations in structures will inform technique for optimizing the scale and operating strategy of hybrid production systems
- Analysis can
  - Identify key parameters for making hybrid nuclear power plants profitable for utility owners
  - Identify key performance parameters where additional R&D is needed for these technologies to be profitable

Thank You

www.nrel.gov

NREL/PR-6A20-81122

This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Hydrogen and Fuel Cell Technologies Office.

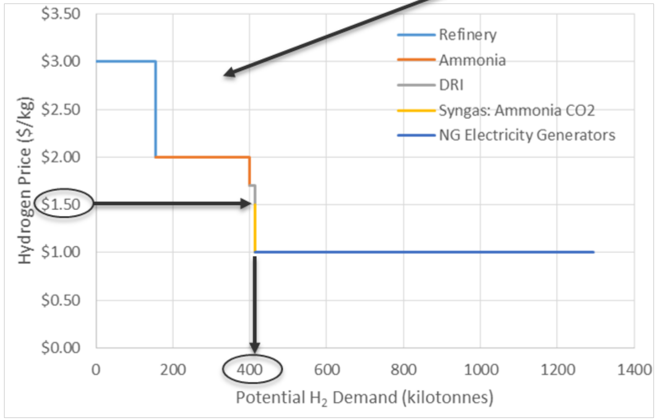
NREL
Transforming ENERGY

Technical Backup and Additional Information

Approach

Developed a Unique Iterative Methodology for Hybrid System Optimization with Varying Electricity Prices

1. Initial H2 price estimate (let's assume $1.5/kg here)



2. That gives us a H2 demand (~410 kilotonnes here)

3. Using the HTE efficiency ($kWh_e/kg\text{-}H_2$), back out the # of hours that yield this demand

4. Back out the electricity price that corresponds to this # of hours

5. Calculate the H2 prices at that electricity price (using HTE efficiency)

If the H2 price does not match the initial estimate, adjust and repeat steps 2-5 until it does.