Fluoride-Salt-Cooled High-Temperature Reactors (FHRs)
Dispatchable Power and Increased Revenue From a Base-load Nuclear Plant with an Air Brayton Power Cycle

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The FHR...

- Is a new reactor concept that is a little over a decade old and originated in the United States
- Combines the coolant from molten salt reactors with the fuel from high-temperature reactors and an air-Brayton combined cycle power system—similar to natural gas plant
- Has attracted the attention of the Chinese who plan to build a 10 MWt FHR by 2017; considering a 100 MWt by 2022 (First new reactor concept to be tested in many decades)
- Provides dispatchable (variable) electricity to boost revenue by 50% relative to base-load nuclear plants (2012 California and Texas wholesale electricity prices) and enables nuclear-renewable electricity grid
- A different pathway to the future with the goal of commercialization by 2030...
The objective of this Integrated Research Project (IRP) is to develop a path forward to a commercially viable salt-cooled solid-fuel high-temperature reactor with superior economic, safety, waste, nonproliferation, and physical security characteristics…
Goals for the Compelling FHR Market Case

- **Environment**: Enable a low-carbon nuclear-renewable (wind / solar) electricity grid by providing economic dispatchable (variable) electricity

- **Economic**: Increase revenue 50% relative to base-load nuclear power plants

- **Safety**: No major offsite radionuclide releases if beyond-design-basis accident (See Added materials)
Evolution of Electricity Markets

Understanding What a Low-Carbon World Implies For Electricity Production is Central to Development of an Advanced Reactor (or any other power system)
For a Half-Million Years Man Has Met Variable Energy Demands by Putting More Carbon on the Fire

Wood Cooking Fire                  Natural-Gas Turbine

Only the Technology Has Changed
Man Will Transition Off Fire
In This Century

Control Climate Change or Fossil Resource Depletion

First Half or Second Half of the Century
Electricity Demand Varies With Time

No Combination of Nuclear and Renewables Matches Electricity Demand

New England (Boston Area) Electricity Demand

Time (hours since beginning of year)
Variable Electricity Demand and Production Leads to Variable Electricity Prices

Hours per Year Can Buy Electricity for Different Prices

2012 California Electricity Prices
Maximize Revenue By Selling Electricity When the Price is High

Cheap Natural Gas and Renewables Shifts Curve Left; That Has Shut Down Some Base-Load Nuclear Plants

Distribution of electricity prices, by duration, at Houston, Texas hub of ERCOT, 2012
California Daily Spring Electricity Demand and Production with Different Levels of Annual Photovoltaic Electricity Generation

Adding Solar and Wind Changes Electricity Prices & Price Structure

Unstable Electrical Grid

Excess Electricity with Price Collapse
Notes on California Solar

- Far left figure shows mix of electricity generating units supplying power on a spring day in California today. The figures to the right show the impact on the grid of adding PV capacity assuming it is dispatched first—lowest operating costs.

- Percent PV for each case is the average yearly fraction of the electricity provided by PV. Initially PV helps the grid because PV input roughly matches peak load. Problems first show up on spring days as shown herein when significant PV and low electricity loads.

- With 6% PV, wild swings in power supply during the spring with major problems for the grid. By 10% PV, on low-electricity-demand days the PV provides most of the power in the middle of the day.

- California has deregulated market in electricity. In a deregulated market PV producers with zero production costs will accept any price above zero. As PV grows, revenue to PV begins to collapse in the middle of the day. Collapsing revenue limits PV new build. Large-scale PV also destroys base-load electricity market while increasing market for peak power when no sun. In the U.S. that gets filled with gas turbines. Similar effects at other times with large wind input.

- This is the challenge of renewables—revenue collapse that limits renewables and impacts the economics of base-load electricity. It is the trap that must be avoided if one wants a low-carbon electricity grid.
A Low-Carbon Electricity Free Market Implies
More Hours of Low / High Price Electricity

Low-Electric-Price Damage to Nuclear Plant Economics

Hours/year Electricity Available At Different Prices

Distribution of electricity prices, by duration, at Houston, Texas hub of ERCOT, 2012

Large Sun and Wind Output Collapses Revenue

No Sun and No Wind

The Future Market?
Revenue Collapse Challenge for High-Capital-Cost Low-Operating Cost Systems

Revenue Collapse at 10 to 15% Solar (Annual Basis), 20 to 30% Wind, and ~70% Nuclear

Nuclear Operating at Expensive Part Load

Wind and Solar With Blackouts or Expensive Energy Storage

Near-term Problem: Consequence of Renewables Subsidies
Long-Term Question: What Replaces Fossil-Fuel Historical Role of Low-Capital-Cost Variable Energy Supply?
Notes on Revenue Collapse

In a free market, excess product collapses the market price to zero. In the U.S. there is a federal production tax credit of $22/MWh(e) for renewables for the first ten years. Because of this subsidy, an owner of a wind farm or solar system will pay the grid up to $21/MWh to take his electricity because he will receive $22/MWh from the federal government. This creates most of the negative price electricity in the U.S. The other common large subsidy is the decision in some states that the grid operator pay for required grid upgrades for renewables rather than the power plant operator. A nuclear power plant operates 90% of the time so the grid connected to the plant is being used 90% of the time. Wind capacity factors are ~30% and solar capacity factors are lower. That implies grid support costs for renewables are two or three times more expensive because the power lines are used fewer hours per year.

In Germany, with a national policy to convert to renewables, renewables policies have resulted in 24% of all electricity from renewables, a doubling of electricity prices and increasing carbon dioxide emissions. The effect of renewables is to depress prices at times of high wind or solar output. This makes capital-intensive low-operating-cost base-load plants less economic—including nuclear plants and future fossil plants with the capability to sequester carbon dioxide. Economics demands that plants that produce electricity for times of low wind and solar output have low capital costs because they will operate fewer hours per year. The economic choice, depending upon country, will often be simple coal plants or simple gas turbines—rather than more capital-intensive lower-operating-cost nuclear, supercritical coal and natural gas combined cycle plants. While a combined-cycle natural gas plant has an efficiency of 60%, simple gas turbines have efficiencies between 30 and 40%. The result is that greenhouse gas emissions can and in some cases have increased as renewables are added to the grid and lower-capital-cost higher-operating cost, less-efficient fossil plants provide power for low-wind and low-solar conditions.

Large scale renewables changes the grid and requires rethinking the rest of the generating system if one is to avoid large increases in electricity costs and significant increased greenhouse gas emissions. At the current time in the U.S. grid, a fraction of the wind would be economic without large subsidies. Economic wind is in locations where land forms create high wind conditions—in that context it is similar to hydro. None of the solar systems on the grid are economic without subsidies or mandates.
Need Nuclear Reactor Designs and Strategies that Can Adjust to the Changing Market

Also Required if Significant Long-Term Renewables

Hours/year Electricity Available At Different Prices

Distribution of electricity prices, by duration, at Houston, Texas hub of ERCOT, 2012
Four Strategies for Dispatchable Nuclear Electricity

- Variable nuclear power output (EPRI LWR program)
- Base-load nuclear with thermal energy storage to produce added peak power (Appendix)
- Base-load nuclear with hybrid energy systems producing a second product and variable electricity
- Fluoride-salt-cooled High-temperature Reactor (FHR) with Nuclear Air-Brayton Combined Cycle (NACC)

MIT Investigating Last Three Options
FHR Commercialization Strategy

Increase Revenue Relative to Base-load Plants
Enable Low-Carbon Nuclear Renewable Grid
FHR with Nuclear Air-Brayton Combined Cycle (NACC)

Constant High-Temperature Heat Reactor (FHR)

Variable Natural Gas, Biofuels or Hydrogen

Gas-Turbine (NACC)

Variable Electricity
FHR with Nuclear Air-Brayton Combined Cycle (NACC)
• Base-load electricity with nuclear heat
• Peak electricity with natural gas [NG] assist
• Sell steam if low electricity prices
• Cogeneration mode enables lower-cost steam
Notes on Nuclear Air Brayton Combined Cycle-I

NACC is more efficient in converting natural gas (NG) or hydrogen (H₂) to electricity than a stand-alone NG combined cycle plant because the NG or H₂ is a topping cycle operating above the 700°C salt coolant. The first generation design has NG-to-electricity efficiency of 66%—far above state-of-the-art conventional NG turbines but with lower peak temperatures in the turbine. At part load the efficiency differences are much larger in favor of an FHR with NACC. This creates major economic incentives for NACC relative to a traditional nuclear power plant and a separate stand-alone NG plant as the price of NG increases or if there are restrictions on greenhouse gas releases. In a low-carbon world it becomes the most efficient method to convert H₂ to electricity.

The load response times for NACC are shorter than stand-alone NG plants because the NACC air compressor is running on nuclear heat. It does not know if there is auxiliary NG injection. In contrast, in a conventional NG plant (or aircraft engine), there is a lag between fuel injection and added power for the compressor to boost air flow. In NG or jet fuel Brayton turbines, the operating windows are controlled by the need to control the fuel-to-air ratio to assure combustion. In NACC the air temperatures are above the auto-ignition temperatures. One can add a small or large amount of fuel and the air flow through the machine does not change.

NACC opens up a variety of industrial heat markets. There is the option for steam sales where the cost and the design of the plant does not change if one is producing electricity or electricity and steam for sale—the heat recovery steam generator remains the same. The air cycle isolates the steam generator from the reactor assuring no possibility of contamination of the steam. This has major implications in terms of reducing carbon dioxide (CO₂) emissions in non-electrical markets by displacing NG. It also produces hot air without combustion products—CO₂ and water. The low humidity air enables drying of biomass and agricultural products with less energy inputs because one does not need added heat to compensate for the water added by the combustion process in normal gas-fired dryers. For processes such as cement production, the preheated hot air reduces the quantities of fossil fuels needed and reduces the CO₂ content of the final hot air. This favorably changes the chemical equilibrium. In cement we want to remove CO₂ from CaCO₃ and higher concentrations of CO₂ in the hot air retards the calcination process. Hot air preheating should improve the process and reduce energy consumption.
Notes on Nuclear Air Brayton Combined Cycle-II

While the mechanical differences between NACC and a natural gas combined cycle plant (NGCC) are relatively small, there are different performance characteristics because NACC in base-load mode is not burning fuel. Fossil-fueled gas turbines have simple gas turbines. NACC has a reheat cycle like a steam plant. Compressed air is heated, goes through a turbine, is reheated, and goes through a second turbine. This enables the 42% efficiency that is similar to some steam cycles and far higher than could be obtained by a simple gas turbine as found in NGCC plants at such temperatures. Reheat cycles are not used in NGCC plants because one runs out of oxygen to reheat the combustion gas a second time.

This specific design was based on minimizing changes relative to the traditional NGCC plant. After the power system design, the market analysis was done using the derived engineering parameters and 2012 hourly price data from California and Texas. The economic analysis came to the conclusion that the NACC would operate most of the year in peak power mode because it is more efficient than any stand-alone natural gas plant in converting natural gas to electricity—66.4%. It gets dispatched first. Based on that knowledge, future designs of NACC would be optimized to maximize natural gas to electricity efficiency.

The limiting design point of NACC is not the turbine temperature which is almost 200° C less than the design limit of the GE 7FB turbine. The limiting design point is the allowable peak temperature in the heat recovery steam generator (HRSG) for the convection-heated steam boiler tubes. The HRSG is a standard system similar to that found in traditional NGCC plants. However, our plant has gas reheat where we have the option to add sufficient natural gas to boost temperatures to the peak allowable turbine limits (no shortage of oxygen). That increases efficiency but the hot exhaust gas exceeds the traditional HRSG peak gas temperatures. For the next design we have the option to add a radiant-heat-recovery boiler-tube section to the HRSG similar to those used for decades in coal-fired power plants. This eliminates the temperature limits in the HRSG. This design change would increase peaking capacity and increase the natural gas to electricity efficiency---probably to somewhere near 70%.
Peaking Power Is a Topping Cycle
High Natural Gas-to-Electricity Efficiency

Base load: 100 MWe; Peak: 241.8 MWe

- Natural Gas:
  - Peaking: 214 MWt → 142 MWe (66.4% Efficiency)
  - Base-load: 236 MWt → 100 MWe (42.5% Efficiency)

- Nuclear Heat
  - Reject Heat: 72 MWt
  - Reject Heat: 136 MWt

FHR Has Multiple Operating Modes*
Chose Operating Mode to Maximize Revenue Each Hour

- Base-load electricity (Nuclear heat): 42% efficient
  - Brayton-cycle electricity to grid
  - Steam to Rankine-cycle electricity to grid

- Peak Electricity (Nuclear + NG peaking)
  - Add NG to boost heat input (66% efficiency)
  - Increase Brayton and Rankin electricity to grid

- Electricity and Variable Steam Sales (Nuclear heat)
  - Brayton-cycle electricity to grid
  - HRSG steam to industry (Sell steam at 90% cost of NG so industry turns down their boilers when low-price electricity)

- Cogen: Electricity and Steam Sales (Nuclear and NG)
  - Brayton-cycle electricity to grid
  - HRSG steam to industry

*Optional 5th Mode of Dumping Hot Air and Operate at House Load
## FHR Revenue Using 2012 Texas and California Hourly Electricity Prices
### After Subtracting Cost of Natural Gas

<table>
<thead>
<tr>
<th>Grid→ Operating Modes</th>
<th>Texas Percent (%)</th>
<th>California Percent (%)</th>
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<tbody>
<tr>
<td>Base Load Electricity</td>
<td>100</td>
<td>100</td>
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<tr>
<td>Base With Peak (NG)</td>
<td>142</td>
<td>167</td>
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<tr>
<td>Base with Steam Sales</td>
<td>142</td>
<td>132</td>
</tr>
<tr>
<td>Cogeneration (NG)</td>
<td>167</td>
<td>182</td>
</tr>
<tr>
<td>Allow All Modes: Chose to Maximize Hourly Revenue</td>
<td>190</td>
<td>214</td>
</tr>
</tbody>
</table>

Why the 50 to 100% Gain in Revenue Over Baseload Nuclear Plants?

- Sell electricity when high prices
  - Base load: 100 MWe
  - Peak: 242 MWe
- Higher peak power efficiency (66.4% vs. best natural gas plant at 60%) so dispatch before stand-alone natural gas plants and boost revenue
  - California: Peak power on 77% of year
  - Texas: Peak power on 80% of year
- Steam sales (if possible) minimizes sales of low-price electricity

Economics = Revenue - Costs

Increasing natural gas prices or limits on greenhouse gas emissions improves FHR/NACC economics because most efficient device to convert natural gas to electricity
Air Brayton Power Cycle Enables Reliable Steam Supply Independent of Reactor
Similar to Existing NGCC Systems in Chemical Plants

Eliminates Historic Nuclear Process Heat Problem: What if the Nuclear Reactor Shuts Down?
For Future Zero-Carbon Electricity Grid, the Likely Auxiliary Fuel is \( \text{H}_2 \)

- Produce \( \text{H}_2 \) at times of low electricity prices by electrolysis or high-temperature electrolysis
- Low-cost daily-to-seasonal storage of \( \text{H}_2 \) like natural gas
- FHR with NACC is the most efficient method to convert \( \text{H}_2 \) to peak electricity—essential for economics
Notes on the Hydrogen Economy and Revenue Collapse Impacts of Renewables

Almost all low-carbon futures include hydrogen. Today hydrogen production consumes ~1% of total energy demand. Most of that hydrogen is used for ammonia (fertilizer) production and converting heavy crude oil into gasoline and diesel. In a low carbon world, hydrogen replaces carbon for such applications as converting iron ore to iron. In the context of biofuels, hydrogen addition can double fuel production per unit of biomass.

The other future application for hydrogen is peak electricity production. For this application, the most important characteristic is the hydrogen-to-electricity efficiency. The FHR with NACC appears to be the most efficient technology for conversion of hydrogen-to-electricity and thus a strong candidate as the preferred method to produce peak electricity from hydrogen in a low carbon world.

The revenue collapse feature of renewables with times of low and high price electricity may define viable hydrogen production technologies in a low-carbon world. If the price of electricity is low for a few thousand hours per year, electrolysis may be an attractive production method because the primary cost is electricity. The other potential hydrogen source is steam reforming of fossil fuels with sequestration of the carbon dioxide. Hydrogen gas in bulk can be stored like natural gas at low costs.

There is the potential that the revenue collapse feature of renewables will eliminate the option of using carbon dioxide scrubbers at the back of conventional fossil plants combined with carbon dioxide sequestration. Periods of very low electricity prices may make such capital-intensive plants uneconomic under any circumstances. The low-cost fossil option with sequestration may become hydrogen production by steam reforming with sequestration of the carbon dioxide. In this case the hydrogen production plant runs at full capacity, the hydrogen goes into storage, and hydrogen can be used to produce peak power with a combined cycle plant such as an FHR with NACC. The hydrogen plant is located near sequestration sites with pipeline hydrogen. In effect, a future system using fossil fuels may be forced to produce hydrogen as its prime product because it can not compete in the electrical market with periods of very low prices.
Fluoride-salt-cooled High-Temperature Reactor

Couple to Nuclear Air-Brayton Combined Cycle (NACC) Power System
FHR Commercial Case Defines FHR Technical Requirements

- Front-end air compressor exit temperature between 350 and 500 °C—Nuclear heat must be at higher temperatures
- Nuclear heat delivery temperatures: 600 to 700 °C
- Other nuclear reactors do not couple to NACC
**Fuel:** High-Temperature Coated-Particle Fuel Developed for Gas-Cooled High-Temperature Reactor fuel with Failure Temperatures >1650° C

**Coolant:** High-Temp., Low-Pressure Liquid- Salt Coolant ($^7\text{Li}_2\text{BeF}_4$) with freezing point of 460° C and Boiling Point >1400° C (Transparent)

**Power Cycle:** Brayton Power Cycle with General Electric off-the-shelf 7FB Compressor

Gas Turbine & Fuel Advances Makes FHR with Nuclear Air-Brayton Combined Cycle Possible, Not Viable 20 years ago
Alternative FHR Designs Can Be Coupled to NACC

Base-line UCB/MIT/UW in Oval

2008 900 MWt PB-AHTR

2010 125 MWt SmAHTTR

2012 3600 MWt ORNL AHTR

2014 236 MWt Mk1 PB-FHR
FHR Uses HTGR Graphite-Matrix Coated-Particle Fuel

Several Alternative Fuel Geometries; Same as NGNP

Our base-case: Pebble-Bed FHR with 3-cm Diameter Pebbles
FHR Uses Fluoride Salt Coolants

- Low-pressure high-temperature coolant
- Base-line salt Flibe ($^7\text{LiBeF}_4$)
  - Melting point 460° C
  - Boiling point: >1400° C
- Heat delivered to power cycle between 600 and 700° C
  - Avoid freezing salt
  - Limits of current materials
- Originally used in Molten Salt Reactor Experiment (MSRE)
  - Molten salt reactor with fuel dissolved in salt rather than solid fuel
  - 8 MWt test reactor that ran successfully in the late 1960s at ORNL

Alternative Fluoride Salt Options Exist
The Salt Coolant Was Originally Developed for the Nuclear Aircraft Propulsion Program—Thus Couples to NACC

It Has Taken 50 Years for Industrial Gas Turbine Technology to Mature to Enable an FHR with NACC
Liquid-Salt Coolant Properties Can Reduce Equipment Size and Thus Costs

(Determine Pipe, Valve, and Heat Exchanger Sizes)

Number of 1-m-diam. Pipes
Needed to Transport 1000 MW(t)
with 100° C Rise in Coolant Temp.

Baseline salt: Flibe: $^7\text{Li}_2\text{BeF}_4$

<table>
<thead>
<tr>
<th></th>
<th>Water (PWR)</th>
<th>Sodium (LMR)</th>
<th>Helium</th>
<th>Liquid Salt</th>
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<tr>
<td>Pressure (MPa)</td>
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<td>Outlet Temp (°C)</td>
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<td>540</td>
<td>1000</td>
<td>To 1000</td>
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<tr>
<td>Coolant Velocity (m/s)</td>
<td>6</td>
<td>6</td>
<td>75</td>
<td>6</td>
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</tbody>
</table>
Fuel and Coolant Choices Imply Safety Case With Large Thermal Margins

- Fuel failure \( \sim 1650^\circ \text{C} \)
  - Iron melts at \( 1535^\circ \text{C} \)
  - Nominal peak \( \sim 800^\circ \text{C} \)
- Coolant boiling \( \sim 1430^\circ \text{C} \)
  - Nominal peak \( \sim 700^\circ \text{C} \)
- Vessel: \( <1200^\circ \text{C} \)
  - Vessel failure before fuel damage
- Much larger margins than any other reactors
Nominal Mk1 PB-FHR Design

- Annular pebble bed core with center graphite reflector
  - Core inlet/outlet temperatures 600°C/700°C
  - Control elements in center reflector
- Reactor vessel 3.5-m OD, 12.0-m high
  - Vessel power density 3 x higher than S-PRISM & PBMR
- Power level: 236 MWt, 100 MWe (base load), 242 MWe (peak w/ NG)
- Power conversion: GE 7FB gas turbine w/ 3-pressure HRSG
- Air heaters: Two 3.5-m OD, 10.0-m high salt-to-air, direct heating
Reactor Building Layout

- Salt-Air Heat Exchangers
- DRACS water pool (typ. 3)
- Reactor
- Air cooled condenser chimney (typ. 3)
Mk1 Salt-to-Air Heat Exchangers Have 36 Annular Sub-bundles

- Baffle plate
- Tube spacer bars
- Hot salt manifold
- Tube-to-tube sheet joints
- Tube lanes (5x4 = 20 tubes across)
- Cool salt manifold
- Air flow direction

Mk1 Tube Sub-bundle Model
Mk1 FHR/NACC Plant Arrangement

Main exhaust stack
Air intake filter
Simple cycle vent stack
Generator
GE F7B compressor
HP/LP turbines
HP air ducts
HP CTAH
Hot well
Reactor vessel

Heat recovery steam generator
Combustor
Hot air bypass
LP air ducts
LP CTAH
Main salt drain tanks

Reactor ← Power Cycle →
# Mk1 PB-FHR Design Parameters

## Reactor Design
- **Thermal power**: 236 MWt
- **Core inlet temperature**: 600°C
- **Core bulk-average outlet temperature**: 700°C
- **Primary coolant mass flow rate (100% power)**: 976 kg/sec
- **Primary coolant volumetric flow rate (100% power)**: 0.54 m³/sec

## Power Conversion
- **Gas turbine model number**: GE 7FB
- **Nominal ambient temperature**: 15°C
- **Elevation**: Sea level
- **Compression ratio**: 18.52
- **Compressor outlet pressure**: 18.58 bar
- **Compressor outlet temperature**: 418.7°C
- **Compressor outlet mass flow**
  (total flow is 440.4 kg/s; conventional GE-7FB design uses excess for turbine blade cooling)
  - 418.5 kg/sec
- **Coiled tube air heater outlet temperature**: 670°C
- **Base load net electrical power output**: 100 MWe
- **Base load thermal efficiency**: 42.5%
- **Co-firing turbine inlet temperature**: 1065°C
- **Co-firing net electrical power output**: 241.8 MWe
- **Co-firing efficiency (gas-to-peak-power)†**: 66.4%

†The co-firing efficiency is the ratio of the increased power produced (total minus base load) during peaking, to the energy input from combustion of natural gas, and represents the efficiency with which the natural gas combustion energy is converted into electricity.
Characteristics of Modular FHR Design

Enabled By Advancing Gas Turbine Technology and HTGR (NGNP) Fuels

- Next-step scale-up from test reactor
- Modular FHR
  - All components rail shippable
  - Factory manufacture
  - Potential market with multi-reactor site option
- Uses existing technology where possible
- Matches GE 7FB gas turbine size
- Future option
  - Scale to larger size
  - Multiple NACC power units per reactor
Notional 12-unit Mk1 station

1200 MWe base load,
2900 MWe peak station output
The Chinese Launched an FHR Program

- Launched an FHR program in 2011 using pebble-bed core (Have pebble-bed HTGR program) and fluoride salt coolant
- ~$400 million budget, 450 person staff. Recently announced upgrade to national project
- 10-MWt test reactor by 2017 focused on commercial scale up of specific concept
- Proposed 100 MWt FHR by 2022
Conclusions

A compelling case is required to develop a new reactor. The FHR has a 3-part case

- 50% increase in revenue vs. base-load nuclear
- Enable nuclear-renewable electricity grid
- No catastrophic off-site accident consequences

Advanced gas turbines and fuels (NGNP) are the enabling technologies for a new reactor—not possible 20 years ago

Significant technical, regulatory, and commercial challenges
Questions
Added Information
Biography: Charles Forsberg

Dr. Charles Forsberg is the Executive Director of the Massachusetts Institute of Technology Nuclear Fuel Cycle Study, Director and principle investigator of the High-Temperature Salt-Cooled Reactor Project, and University Lead for Idaho National Laboratory Institute for Nuclear Energy and Science (INEST) Nuclear Hybrid Energy Systems program. Before joining MIT, he was a Corporate Fellow at Oak Ridge National Laboratory. He is a Fellow of the American Nuclear Society, a Fellow of the American Association for the Advancement of Science, and recipient of the 2005 Robert E. Wilson Award from the American Institute of Chemical Engineers for outstanding chemical engineering contributions to nuclear energy, including his work in hydrogen production and nuclear-renewable energy futures. He received the American Nuclear Society special award for innovative nuclear reactor design on salt-cooled reactors. Dr. Forsberg earned his bachelor's degree in chemical engineering from the University of Minnesota and his doctorate in Nuclear Engineering from MIT. He has been awarded 11 patents and has published over 200 papers.

http://web.mit.edu/nse/people/research/forsberg.html
Goals Define Reactors

Goals and FHR Papers Addressing those Goals

- **Economics**¹, ², ³
- Enable low-carbon nuclear-renewable grid¹, ², ³
- **Safety**: BDBA⁴
- **Resource Extension** (long-term fuel supply)⁵
- **Waste Management**⁶
- **Nonproliferation**⁶

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1. Revenue is expected to be >50% larger than a base-load nuclear power plant: See also: D. Curtis and C. W. Forsberg, Transactions 2014 American Nuclear Society Annual Meeting, Reno, June 2014.
4. M. Minck, Preventing Fuel Failure for a Beyond Design Basis Accident in a Fluoride Salt Cooled High-Temperature Reactor, MS Thesis, Department of Nuclear Science and Technology, Massachusetts Institute of Technology, September 2013
5. The FHR will have about 50% better uranium utilization than an LWR depending upon design details.
6. Waste management and nonproliferation characteristics are a consequence of fuel choices. The FHR is similar to HTGR SNF. Repository performance is expected to be more than an order of magnitude better than LWR SNF. See: C. Forsberg and P. Peterson, “Spent Nuclear Fuel Management for Salt-Cooled Reactors: Storage, Safeguards, and Repository Disposal”, Paper 14010, Proceedings of ICAPP 2014, Charlotte, USA, April 6-9, 2014
Risk Profile for FHR with NACC
Relative to Other Advanced Reactors

- **Technical**
  - NACC
  - Reactor

- **Market**
  - Variable Power Output

- **Institutional**
  - Low-Carbon World

Reactor Technology Development Risk Higher Because No FHR Has Been Built, Lower Market (Higher Revenue) and Institutional (Variable Power for Low-Carbon World) Risks
FHR with NACC Has Lowest Cooling Requirements of Any Nuclear Plant

- Cooling requirements are ~40% of an LWR per unit of electricity that reduces siting constraints
  - Higher efficiency (42%) than an LWR (33%)
  - Combined cycle plants reject a large fraction of their heat as hot air rather than through steam condenser
- FHR with NACC has significantly lower cooling requirements than an FHR with a traditional steam or supercritical power cycle
- Opens up siting options and reduces costs if dry cooling is required*

FHRs Thermal Limits on Fuel, Coolant, and Structural Materials Match Requirements for Driving Air Cycles

Coated particle fuel

Liquid fluoride salt coolants

Nickel-based structural materials
1) Intermediate HX (for power production)
2) DRACS (Passive Decay Heat Removal System)
3) BDBA Heat Removal System (for complete system failure)
Beyond Design Basis Accident (BDBA) Goal Is to Prevent Large-Scale Radionuclide Release

- If peak fuel temperatures below fuel failure temperatures, no major releases
- System design to prevent fuel overheating
- Fuel temperature depends upon heat generation rate (decay heat) versus heat removal rate
  - Generation rate use ANSI decay heat rate curve
  - Heat removal depends upon:
    - Temperature drop to drive heat to environment
    - Resistance to decay heat flow to environment

Heat Removal = Heat Conductivity \cdot \Delta \text{Temperature}
FHR Fuel And Coolant Provide Very Large $\Delta T$ To Drive Decay Heat to Environment in a Severe Accident

- Fuel failure $>1650^\circ C$
  - Iron melts at $1535^\circ C$
  - Nominal peak: $\sim800^\circ C$
- Coolant boiling $\sim1430^\circ C$
  - Nominal peak $\sim700^\circ C$
- Vessel failure: $<1200^\circ C$
- Different than any other reactor

In core feedback: higher temperatures yield negative Doppler with power drop, lower salt viscosity with higher flows and $T^4$ radiation heat transfer.
BDBA Design Maximizes Thermal Conductivity to Environment

Vessel Insulation Failure and Molten Salt Minimize Accident Temperature Drop from Fuel to Silo Wall to Provide $\Delta T$ To Drive Decay Heat to Environment
Tradeoffs Between Power Cycles

Nuclear Air-Brayton Combined Cycle (NACC)
- 42.4% efficiency (Current design)
- 66.4% peaking with natural gas to electricity
- 40% cooling water requirements per kW(e)h of LWR
- >50% increase in revenue vs. base-load plant
- Rapid technology advance of gas-turbine technology

Steam cycle\(^1\)
- 45% efficiency
- No significant improvement likely

Supercritical carbon dioxide cycle\(^1\)
- 48% efficiency
- Small early pilot-plant development stage

\(^1\)S. R. Greene et al., “Pre-Conceptual Design of a Fluoride-Salt-Cooled Small Modular Advanced High-Temperature Reactor (SmAHTR), Oak Ridge National Laboratory, ORNL/TM-2010/199, December 2010
Basis for Choosing Power Cycles

Different Markets: Different Power Cycles

For most of the world, NACC preferred power cycle
- Variable power output
- Lower water consumption (cooling demand)

Higher base-load efficient power cycles preferred in some locations
- If economic variable power output from other sources (large hydro electric capacity, etc.)
- Grid that is primarily base-load electricity
- Sufficient FHRs with NACC built to meet variable electricity demand

NACC may be the most efficient base-load power cycle by time an FHR is deployed (2030) because 100 times more R&D going into Brayton Power Cycles than all other types of power cycles
<table>
<thead>
<tr>
<th>Plant type (Capacity factor)</th>
<th>Levelized Capital (Includes Transmission Upgrade)</th>
<th>Variable O&amp;M</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Dispatchable</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal (85%)</td>
<td>66.9</td>
<td>29.2</td>
<td>100.1</td>
</tr>
<tr>
<td>Coal with CCS (85%)</td>
<td>89.6</td>
<td>37.2</td>
<td>135.5</td>
</tr>
<tr>
<td>NG Combined Cycle (87%)</td>
<td>17.0</td>
<td>48.4</td>
<td>67.1</td>
</tr>
<tr>
<td>NG Turbine (30%)</td>
<td>47.6</td>
<td>80.0</td>
<td>130.3</td>
</tr>
<tr>
<td>Nuclear (90%)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Non Dispatchable</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind (34%)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind offshore (37%)</td>
<td>199.1</td>
<td></td>
<td>221.5</td>
</tr>
<tr>
<td>Solar PV (25%)</td>
<td>133.4</td>
<td></td>
<td>144.3</td>
</tr>
<tr>
<td>Solar thermal (20%)</td>
<td>220.1</td>
<td></td>
<td>261.5</td>
</tr>
</tbody>
</table>

*High Capital Cost Fossil*

*High Operating Cost Fossil*

**Low Carbon World Implies Shifting to High-Capital-Cost Energy Systems Where Need Full Facility Utilization**
General Reports

DRAFT FOR IRP REVIEW

Mark-1 PB-FHR Technical Description

Technical Description of the “Mark 1” Pebble-Bed Fluoride-Salt-Cooled High-Temperature Reactor (PB-FHR) Power Plant

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Jae-Kwun Choi
Alexandre Y. K. Chong
David L. Kunnwiede
Lakshana R. Haddar
Kathryn D. Haff
Michael R. Lauer
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Nicolas Czwebrum
Ehsed Greenspan
Per F. Pederson

UCBTH-14-002
Revision B (DRAFT)
January 2014
Department of Nuclear Engineering
University of California, Berkeley

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NEUP
U.S. Department of Energy

Technical Description of the Mark-1 PB-FHR Power Plant 1 | 1

FLUORIDE-SALT-COOLED HIGH-TEMPERATURE REACTORS (FHRs) FOR BASE-LOAD AND PEAK ELECTRICITY, GRID STABILIZATION, AND PROCESS HEAT

A Joint Project of the Massachusetts Institute of Technology (MIT), University of California at Berkeley (UCB), and University of Wisconsin (UW)

Charles Forsberg (MIT), Lin-wen Hu (MIT), Per F. Pederson (UCB), and Kumar Sridharan (UW)

January 2013
MIT-ANP-TR-147
FHR and IRP History

History

- Concept developed by Forsberg, Peterson, and Pickard
- Combined technologies from high-temperature reactors, molten-salt reactors, sodium-cooled reactors, and air-Brayton power cycles
- Concept made possible by advances in HTGR fuel and utility gas turbines—would not have been viable reactor concept 20 years ago
- 2011 Chinese commitment to build FHR test reactor

Integrated Research Program

- DOE funded, third year of activity
- Three universities: MIT, U of California at Berkeley and the University of Wisconsin
- Industrial partner: Westinghouse
- Advisory panel
  - Regis Matzie (Chairman), retired senior vice president and chief technology officer of Westinghouse
  - Doug Chapin, previous principal at MPR and current senior consultant
  - John McGaha, retired senior executive of Entergy Nuclear
  - Dan Mears, president and CEO of Technology Insights
  - Jim Rushton, retired head of nuclear division at ORNL and managed the defueling of the Molten Salt Reactor Experiment at ORNL
  - Robert Budnitz, expert in nuclear safety, served as Deputy Director and then Director of the NRC Office of Nuclear Regulatory Research
The molten-salt–cooled Advanced High-Temperature Reactor (AHTR) is a new reactor concept designed to provide very high-temperature (750 to 1000°C) heat to enable efficient low-cost thermochemical production of hydrogen (H₂) or production of electricity. This paper provides an initial description and technical analysis of its key features. The proposed AHTR uses coated-particle the boiling points for molten fluoride salts are near ~1400°C, the reactor can operate at very high temperatures and atmospheric pressure. For thermochemical H₂ production, the heat is delivered at the required near-constant high temperature and low pressure. For electricity production, a multireheat helium Brayton (gas-turbine) cycle, with efficiencies >50%, is used. The
Energy Storage Systems

Nuclear Produces Heat
Unique Nuclear Options Use Heat Storage

Charles Forsberg and Steven Aumeier, “Nuclear-Renewable Hybrid System Economic Basis for Electricity, Fuel, and Hydrogen,” 2014 International Congress on Advanced Nuclear Power Plants
American Nuclear Society, Charlotte, North Carolina, April 6-9, 2014
Using Storage to Fully Utilize Generating Assets to Meet Demand

Wind

Solar
Thermal and PV

Heat

Heat Storage

Heat To Electricity

Nuclear

Variable Electricity

Electricity Storage
Pump Storage
Batteries
Etc.
Three Storage Challenges

- Different storage durations and viable storage media
  - Hourly: chemical (batteries), smart grid (delay demand)
  - Days: water (pumped storage), compressed air storage
  - Seasonal: hydrogen and heat

- Required storage depends upon mismatch between
  - Generation
  - Demand

- The big challenge is seasonal storage
  - Hourly storage device used (cycled) 365 days per year
  - Seasonal storage device used (cycled) 1 to 2 uses per year
  - Seasonal storage media has to cost less than 1/100 of a storage media used for hourly storage
### California Electricity Storage Requirements
As Fraction of Total Electricity Produced

Assuming Perfect No-Loss Storage Systems

<table>
<thead>
<tr>
<th>Electricity Production Method</th>
<th>Hourly Storage Demand</th>
<th>Seasonal Storage Demand$^a$</th>
</tr>
</thead>
<tbody>
<tr>
<td>All-Nuclear Grid</td>
<td>0.07</td>
<td>0.04</td>
</tr>
<tr>
<td>All-Wind Grid</td>
<td>0.45</td>
<td>0.25</td>
</tr>
<tr>
<td>All-Solar Grid</td>
<td>0.50</td>
<td>0.17</td>
</tr>
</tbody>
</table>

$^a$Assume smart grid, batteries, hydro and other technologies meet all storage demands for less than one week

Solar Characteristics Solar Imply Large Storage Requirements
California PV Solar if Meet 10% Total Yearly Electricity Demand

- Added PV output primarily in the middle of the day
- Quickly exceed demand so extra PV goes to storage
- Implies high storage requirements for a solar-only system
The Lower Nuclear Storage Requirements Reflect the Electricity Demand Curve

Most of the Output ( ) of First Nuclear Plants Above Base-load Goes to the Grid Reducing Storage Requirements, Less to Storage

New England (Boston Area) Electricity Demand
Nuclear As a Large-Scale Heat Generating Technology Preferentially Couples to Heat Storage Technologies

Economics of Scale and Grid Characteristics Favor Nuclear Technology

<table>
<thead>
<tr>
<th>Technology</th>
<th>Size (MWh)</th>
<th>Heat Storage Intrinsically Cheaper than Electricity Storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam Accumulator</td>
<td>To $10^4$</td>
<td></td>
</tr>
<tr>
<td>Geothermal Hot Water</td>
<td>$10^4$ to $10^6$</td>
<td></td>
</tr>
<tr>
<td>Geothermal Rock</td>
<td>$10^6$ to $10^7$</td>
<td></td>
</tr>
</tbody>
</table>
Nuclear Heat Storage System Can be 10 to 100 Larger than a Solar Thermal Power Storage System

Capital Cost per Unit Storage in Nuclear System Should Be a Small Fraction That of a Solar Thermal Power Plant

<table>
<thead>
<tr>
<th>Increase in System Size</th>
<th>Exponential Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.6</td>
<td>0.7</td>
</tr>
</tbody>
</table>

Size Scaling Law Relative Capital Cost per Throughput

<table>
<thead>
<tr>
<th></th>
<th>0.25</th>
<th>0.20</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.063</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>0.040</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td></td>
</tr>
</tbody>
</table>

LWR Storage System Includes the Storage Media, Heat Exchangers, Steam Turbines, & Generators for Peak Power
## Heat Storage Technologies

### Scale of Storage Challenge in Low-Carbon Grid ~ $10^9$ MWhr/yr

<table>
<thead>
<tr>
<th>Technology</th>
<th>Description</th>
<th>Storage Time (Hr)</th>
<th>Size (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solid-Liquid Heat Capacity*</td>
<td>Store nitrate or other material at low pressure</td>
<td>$10^1$</td>
<td>To $10^4$</td>
</tr>
<tr>
<td>Steam Accumulator*</td>
<td>Store high-pressure water-steam</td>
<td>$10^1$</td>
<td>To $10^4$</td>
</tr>
<tr>
<td>Geothermal Hot Water</td>
<td>Store hot water 1000 m underground at pressure</td>
<td>To $10^2$</td>
<td>$10^4$ to $10^6$</td>
</tr>
<tr>
<td>Geothermal Rock</td>
<td>Heat rock to create artificial geothermal</td>
<td>To $10^4$</td>
<td>$10^6$ to $10^7$</td>
</tr>
</tbody>
</table>

*Near-term Technical Options for Peak Power with Heat Storage, Economics Not Understood

Seasonal Heat Storage Technology: Hot-Rock Geothermal Storage

System Physics Requires ~0.1 GWy Storage Capacity: Long-Term Option

Thermal Input to Rock

Nuclear or Very Large Solar Thermal

Pressurized Water for Heat Transfer

Fluid Return

Fluid Input

Geothermal Plant

Thermal Output From Rock

Permeable Rock

Cap Rock

Nesjavellir Geothermal power plant; Iceland; 120MW(e); Wikimedia Commons (2010)

Early R&D Stage
Hybrid Systems

Producing Higher-Value Non-Electricity Products When Low-Price Heat and Electricity is Available

Charles Forsberg and Steven Aumeier, “Nuclear-Renewable Hybrid System Economic Basis for Electricity, Fuel, and Hydrogen,” 2014 International Congress on Advanced Nuclear Power Plants
American Nuclear Society, Charlotte, North Carolina, April 6-9, 2014
Using Hybrid Systems to Fully Utilize Electricity Generating Assets

- Wind
- Solar Thermal & PV
- Nuclear and Solar-Thermal Air-Brayton Combined Cycle

Other Products

H₂

Other

Variable Electricity

Hybrid Systems
Hydrogen: Sink for Excess Electricity
Feedstock for Fuels and Industry

Electricity Production $\rightarrow$ H$_2$ / O$_2$ From Water $\rightarrow$ Markets

Electricity $\rightarrow$ Electrolysis

Electricity and Heat $\rightarrow$ Heat $\rightarrow$ HTE

Fuel, Fertilizer, Metals

Peak Power
Why Low-Carbon Futures Always Have Hydrogen

- Fossil fuel substitutes for low-carbon economy
- Massive current and future hydrogen market: 1% of U.S. energy consumption today
  - Transportation
    - Used in oil refining: convert heavy oil to gasoline
    - Can double liquid fuel yields per ton of biomass
    - Direct fuel use options: hydrogen, ammonia, or other forms
  - Fertilizer (ammonia)
    - Replace coal in the production of iron and other metals
- Storable using the same technologies as used for NG
- Potentially economic if using off-peak electricity
Hydrogen Is the Backstop Technology to Unlimited Liquid Fuels from Air

Energy Input is Primarily Making Hydrogen

Extract CO₂

→ Convert CO₂ and H₂O To Syngas

Heat + Electricity

CO₂ + H₂O → CO + H₂

→ Conversion to Liquid Fuel

CO + H₂ → Liquid Fuels

Carbon Dioxide From Air

High Temperature Electrolysis (One Option)

Fischer-Tropsch Process

Early R&D Stage
Low-Carbon Grid Conclusions

- A low-carbon world is coming in this century
- Must use capital-intensive nuclear and renewable power systems at maximum capacity to minimize societal costs
- Three strategies for efficient use of nuclear generating assets
  - Storage
  - Hybrid systems
  - Non-fossil dispatchable power systems (FHR with NACC)
- Major technical challenges
The New Grid

- Wind
- Solar Thermal & PV
- Nuclear
- Hybrid Systems
- Other Products
- Heat Storage
  - To Electricity
- Electricity Storage
  - Pump Storage, Batteries, Etc.
- Nuclear and Solar-Thermal Air-Brayton Combined Cycle

Variable Electricity

Heat

H₂